CANADIAN AND U.S.
HEAVY CRUDE OI[illegible] MARKETS:
A REVIEW AND PROSPECTS

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The following abbreviations have been used throughout this study and are defined as follows:

NA	not applicable
NR	not reported
-	zero
--	amount too small to be expressed
( )	negative value (when around a given figure)
Mb/d	thousand barrels per day
MMb/d	million barrels per day

PREFACE

This study was undertaken during 1984 and completed in January 1985. Most of the data assembly and the analysis, however, was completed during the period from June to September of 1984.

The Institute is grateful for helpful comments on an earlier draft of the study by a four-member Advisory Committee comprised of two representatives from the heavy oil industry and two specialists from federal and provincial energy departments.

Thanks are due to the various industry and government officials for time spent in valuable meetings and exchanges which helped to shape the study and to strengthen the analysis. The authors themselves, however, are solely responsible for the conclusions drawn, and for any errors or omissions which may remain.

The principal authors of this study were C. Slagorsky, A. Webster and J. Pasay. Considerable assistance was provided by S. Cain, G. Morrison, S. Poohkay, J. Rashid and S. Streifel. In addition, P. Christensen, B. Cox, and A. Crowley assisted in the collection of data; D. Peterson, in graphics preparation; J. Morrison, J. Stinn and S. Ingstrup, in typing the final document and the several drafts which preceded it.

EXECUTIVE SUMMARY

This study regarding the potential for exporting Canadian heavy crude oil (less than or equal to 29° API) has found that, in general, an export market exists which could be satisfied by forecast supply under somewhat improved logistical capabilities. Specifically, the conclusions may be summarized as follows:

Crude Oil Price Differentials

- Current spot market crude oil price differentials between light and heavy crude oils are narrow--about $0.80 (U.S.) between Arabian Light and Heavy on the U.S. Gulf Coast as of December 1984--and, therefore, not conducive to increased demand for heavy crude oil. However, in the short term, the absolute price of crude oils of various quality are of greatest importance to refiners in determining their production levels. Differentials are more relevant to long-term refinery investment decisions.
- Official and spot market crude oil price differentials have both varied widely over time, and have not given rise to a generally accepted theory for accurately predicting future differentials due to complex interactions between the many factors affecting differentials.
- In general, crude oil price differentials are expected to narrow in the short term due to excess supply of light crude oil and increasing demand for heavy crude oil as refinery capacity for the latter increases. In the long term, differentials are expected to widen as the supply of light crude oil ultimately declines relative to heavy crude oil.

Canadian and U.S. Supply, Demand and Disposition of Crude Oil

- Total Canadian crude oil production declined 25 percent from 1973 to 1983, but total heavy crude oil production increased 40 percent over the same period. Future Canadian crude oil production will depend increasingly on Canadian heavy crude oil reserves. However, Canadian demand for heavy crude oil has been declining faster than Canadian demand for all crudes. The former declined 42 percent from 1980 to 1983, while the latter decreased 18 percent over the same period.
- Total U.S. crude oil production decreased 6 percent from 1973 to 1982 primarily due to a 34 percent production decline in Petroleum Administration for Defence (PAD) District III. This resulted mainly from a 29 percent decrease in Texan production over that period. PADD V production more than doubled over the same period largely due to a sevenfold increase in Alaskan production.

- Canadian crude oil exports to the U.S. increased 9 percent from 1978 to 1983, with heavy crude oil accounting for over 70 percent of 1983 volumes compared with only 51 percent in 1980.

- Nine U.S. refineries accounted for 92 percent of 1983 U.S. imports of Canadian heavy crude oil. Nominations for Canadian heavy crude oil by these refineries doubled from 1981 to 1983; authorized exports to the same refineries increased even more rapidly over the same time period.

- Potential demand for Canadian heavy crude oil by both Canadian and U.S. refineries could not be accurately determined due to data limitations. Specifically, the required data include disposition data of Canadian and imported heavy and light crude oil to individual Canadian refineries; production, reserves, and disposition data for U.S. domestic crude oil production by crude type and refinery; and refined product slates produced by a given refinery with a given quality of crude oil. These data are generally not publicly available.

Forecast Canadian Supply, Demand and Exportable Surplus of Heavy Crude Oil

- Based on a synthesized forecast, total Canadian supply of heavy crude oil is forecast to increase at an average annual rate of 0.6 percent from 1984 to 2000. In contrast, Canadian demand for the same is projected to increase at an average rate of 4.4 percent per annum from 1983 to 2000. Total Canadian and U.S. demand for Canadian heavy crude oil is expected to increase at 3.7 percent per year over the same period. These base case results include two upgraders with capacity of 8000 cubic metres per day each.

- Under base case world oil price assumptions, the exportable surplus of Canadian heavy crude oil for the year 2000 is 29 900 cubic metres per day without upgraders, and 5900 cubic metres per day with two heavy oil upgraders built in Canada. Under the former case, the exportable surplus increases at an average annual rate of 0.8 percent from 1984 to that level, while in the latter case it decreases at an average rate of 8.9 percent per annum from 1984 to 2000. Some exportable surplus exists throughout the forecast period in all cases analyzed, except in the low price case with upgraders.

Canadian Penetration of the U.S. Heavy Crude Oil Market

- Canadian heavy crude oil accounted for 81 percent of all U.S. heavy crude oil imports in 1983. PADDs I and II received 2 percent and 93 percent, respectively, of the total imports, and similar percentages of the Canadian imports.

- The potential for Canadian heavy crude oil exports to the U.S. is enhanced by crude oil price decontrol in the U.S., incentives to U.S. refineries to upgrade their facilities, and the U.S. federal highway pavement program which required an estimated 5.5 million tonnes of asphalt in 1983. (The pavement program terminates in 1988.)

- The exportable surplus of Canadian heavy crude oil could find a market in the U.S., especially since U.S. domestic crude oil production is forecast to decrease 5 percent from 1983 to 2000. On the other hand, total U.S. crude oil demand is also expected to decline which could partially offset the market potential.

- Sales of Canadian heavy crude oil could be increased by the construction of new or the reversal of existing pipelines to new U.S. markets. The Patoka/Wood River area in Illinois in particular could be a major new market for Canadian heavy crude oil. However, exports into new markets may require reductions in the level of government taxes and/or royalties and other charges currently imposed.

- In the short term, Canadian heavy crude oil exports to traditional markets may be hindered by a possible capacity shortage in the Interprovincial Pipe Line (IPL) system. Although increased volumes of heavy crude oil will exacerbate this shortage, IPL's current expansion plans are expected to result in some excess capacity by 1985.

The Impact of Diluent Availability

- A possible shortage of pentanes plus (currently the most commonly used diluent) for use as a heavy crude oil diluent could limit exports of Canadian heavy crude oil to the U.S. Based on other studies, such a shortage is forecast for as early as 1986.

- Current regulation of pentanes plus appears to be depressing the price, resulting in excessive use and insufficient research into alternatives.

- Based on domestic demand for pentanes plus other than diluent demand, and the diluent requirements for the exportable surplus defined above, only a limited supply shortfall of 1600 to 2300 cubic metres per day is expected from 1984 to 1987. Thereafter, an increasing surplus is projected to the year 2000, calling into question whether pentanes plus supply will actually be a constraint on exports of Canadian heavy crude oil.

Netbacks to Canadian Heavy Crude Oil Producers, and the Impacts of Deregulation

- Illustrative calculations of the netback to a Canadian producer from exporting heavy crude oil to the Chicago market indicate that the netback would decrease 18 percent on average under oil market deregulation. Specifically, the netback for Lloydminster heavy crude oil would decline from $196.95 (Cdn.) to $170.25 per cubic metre. The netback for Cold Lake heavy crude oil could decline more substantially, from $176.05 to $137.26 per cubic metre. The decrease under deregulation is largely due to the lower heavy crude oil prices and the increase in diluent cost which increases the value of the deblending adjustment.

- Under the current system, the National Energy Board effectively "markets" Canadian heavy crude oil in the U.S. through its export charge which is the balance between the U.S. market price and the delivered domestic (COOP) price of crude oil. Thus, the netbacks under the deregulated case are likely more reflective of the true value of Canadian heavy crude oil in the U.S. Given that the netback for Lloydminster heavy crude oil under deregulation falls between the COOP and NORP prices for the summer of 1984 ($161.55 and $204.95 per cubic metre, respectively), Cold Lake heavy crude oil production could become only marginally economic under deregulation, assuming no change in taxation and royalty regimes.

Implications for Canadian Energy Policy and Heavy Oil Marketing

- Deregulation of Canadian crude oil prices in both the domestic and export markets is desirable. This would have a beneficial effect in terms of increased efficiency of Canadian heavy crude oil production, and more stable and possibly increased demand for Canadian heavy crude oil if U.S. buyers anticipated that the Canadian price would remain competitive with alternative sources.

- Lower producer netbacks from the sale of Canadian heavy crude oil to the Chicago market under the deregulation scenario imply that the current regulated price (COOP plus NORP supplement) has been greater than market value. Decreases in U.S. refinery nominations for Canadian heavy crude oil due to its relatively high price prior to the price adjustments announced by Canada in January emphasize the sensitivity of export demand to export prices.

- Possible decreases in producers' netbacks under deregulation suggest that production by marginal producers could become uneconomic. In this way market forces would serve to encourage maximum operating efficiency in new and planned recovery operations.

- Under deregulation, Canadian heavy crude oil producers and/or exporters would negotiate selling prices of Canadian heavy crude oil themselves rather than effectively deferring decisions on such matters to the National Energy Board. The loss of the NORP supplement by a producer would be partially offset by the simultaneous elimination of the Board's export change. The producer would then absorb any loss or receive any available margin.

- Deregulation of condensate and pentanes plus prices and marketing rules by the Alberta Government needs to be given serious consideration. Such deregulation would improve the efficiency of condensate/pentanes plus allocation and tend to increase the volumes available as heavy oil diluent. This is important because diluent shortages forecast for the late 1980s could hinder the development and transportation of Canadian heavy crude oil resources.

- If deregulation of pentanes plus prices and abandonment of the related marketing rules led to an increase in the cost of diluent, this could be expected to increase research into alternative means of transporting heavy crudes which could be key to Canadian heavy crude oil exports in the future. Higher diluent prices would encourage capital investment in upgrading facilities either at conventional refineries or at stand-alone sites. Heavy oil upgrading in Canada would, in turn, create a significant number of jobs and investment opportunities, and contribute to oil self-sufficiency and the development of Canadian technology. The economics of heavy oil upgrading, however, will mainly depend on the course of price differentials between light and heavy crudes.

- If required, fiscal incentives for heavy oil projects should be in terms of concessions until project pay out and/or reduced royalty/tax levies, rather than direct subsidies or price guarantees. The arguments for incentives are strong, but fiscal regimes must be flexible enough to allow investors a reasonable rate of return which takes the inherent risks of their investment into account.

Recommendations for Further Study

- More detailed and precise conclusions could be reached using the methodology provided by this study if more detailed data were available. Additional work would require disaggregated U.S. heavy crude oil supply, demand, and disposition data by crude type, state, and refinery; disaggregated data on Canadian and imported heavy crude oil disposition to Canadian refineries; and more complete information on the factors affecting differentials.

Chapter 1

INTRODUCTION

1.1 Overview and Objectives

The objective of this study is to analyze the market potential for Canadian heavy crude oil and to identify the salient forces affecting this potential over the period 1984 to 2000. The objective is achieved by reviewing and evaluating the main factors affecting the market potential. First, international crude oil price differentials are reviewed, the expected future pressures on these differentials are identified, and the impact these factors will have on the future Canadian and United States market prices for heavy crude oil is delineated. Second, the available historical data pertaining to Canadian heavy crude oil markets are reviewed, and data limitations and trends in market developments are identified. Third, potential Canadian heavy crude oil supply, demand, exportable surpluses, and deliverability constraints, such as availability of diluent, are determined. Fourth, the United States market potential, giving due consideration to the expected United States refined petroleum product slate and refinery configurations, is identified. Finally, the impacts on producer netbacks and Canadian supply as a result of the expansion of Canadian heavy crude oil in the United States market are delineated.

This study was motivated by recent changes and expected future changes in world oil markets and, in particular, the North American oil markets regarding: (1) the composition of the crude oil slate; (2) price differentials between light and heavy crude oils; (3) modifications to refinery configurations; and (4) refined petroleum product demands. These factors have stimulated interest in the future role of heavy crude oil in crude oil markets.

Generally, heavy crude oil is more expensive to produce, transport and refine than light crude oil. Under appropriate price differentials that cover these higher costs, heavy crude oil can be substituted for light crude as a refinery feedstock. However, as the refined petroleum product slate tends toward heavier products such as asphalt, light crudes tend to lose their comparative advantage vis-a-vis heavy crudes.

In North America, and Canada in particular, there is a continuing tendency for an increasing proportion of heavy crude oil in the composition of domestic crude oil production. This change is a result of a decrease in the production of light crude, reflecting the depletion of light crude oil reserves, and an increase in the production of heavy crude oil, reflecting an increase in both reserves and production levels.

Maintaining or increasing Canadian production of heavy crude oil depends on a number of factors. The most important of these are the size of the reserve base, cost of production, market price, light/heavy crude oil price differential, availability of competing crude oils, deliverability, regulatory environment, refinery configuration, and the demand for refined petroleum products. These factors must be considered when evaluating the future market potential for Canadian heavy crude oil.

In the last few years, the majority of Canadian heavy crude oil production has been exported to the United States, in particular to the northern and northeastern states. During the 1980s, a single U.S. refinery has acquired approximately 70 percent of the Canadian heavy crude oil exports to the United States. These volumes account for over 90 percent of this refiner's 1983 crude oil throughput capacity.

While there have been considerable changes in Canadian refinery configuration over the last decade, there has not been any significant increase in Canadian refinery demands for Canadian heavy crude oil. Increases in Canadian demand for domestic heavy crude oil have reflected increased feedstock requirements for the upgrading of heavy crude oil to synthetic oil. Therefore, expansion of heavy crude oil markets may well depend primarily on United States market potential. Nevertheless, the synthesized forecasts of Canadian demand growth for domestic heavy crude oil production, as developed in Chapter 4, suggest that this demand growth will actually exceed similar forecasts of U.S demand growth for Canadian heavy crude oil.

1.2 Definitions

1.2.1 Heavy Crude Oil

The definition of heavy crude oil used in this report is the one provided by the National Energy Board in Canadian Energy Supply and Demand: 1980-2000.[1] Heavy crude oil includes the following:

- Lloydminster-type blended crude oil delivered to the Interprovincial Pipe Line (IPL) system either at Hardisty, Alberta or at Kerrobert, Saskatchewan,
- Wainwright and Viking-Kinsella blended crude oils delivered to the Interprovincial Pipe Line system at Hardisty, Alberta,
- Chauvin crude oil delivered to the Interprovincial Pipe Line system through the BP Exploration Canada Limited Chauvin-Hardisty pipeline system,
- Area III medium crude oil in Saskatchewan (Fosterton),
- The Bow River Pipelines Ltd. stream in Alberta, excluding light and medium crude oil normally batched separately,
- Area II blended heavy crude oil in Saskatchewan excluding light crude oil normally batched separately (Smiley-Coleville),
- Area IV medium crude oil in Saskatchewan (Midale-Weyburn), and
- Other crude oil with API gravity less than 25° API.

This definition includes a wide range of crude qualities.[2] Also included in the definition is heavy oil produced from the oil sands and bitumen, which is a heavy crude with an API gravity typically less than 10°. In some instances, the feedstock for the oil sands plants producing synthetic crude would also be included.

A more general classification of crude oil frequently employed is the grouping of crude oil as conventional or non-conventional. Non-conventional crude includes crudes obtained by mining operations and in-situ methods from the oil sands. Generally, the term non-conventional crude encompasses all crude reserves that do not flow freely without the application of external energy. Otherwise, the crude would be referred to as conventional. As a result, non-conventional crude oil is usually heavy.

1.2.2 Diluent

Diluent is a substance added to heavy crude oil that results in a blended stream that is more readily moved by conventional methods, such as pipelining. It is not possible to pipeline a wide range of the crudes encompassed by the definition utilized in this report without the use of diluents. Diluent is normally a mixture of light (low specific gravity) hydrocarbons. The usual hydrocarbon components utilized as diluent are pentanes plus. Pentanes plus are obtained by processing raw natural gas, condensate or crude oil. Condensate, a term often used interchangeably with pentanes plus, is an equivalent hydrocarbon mix recovered at the wellhead. Condensate has an API of greater than 40°.

1.2.3 Synthetic Crude

Synthetic crude oil is crude oil that has been upgraded or processed. The crude oil feedstock could be either conventional heavy crude oil or bitumen obtained by either mining operations or in-situ recovery methods. Synthetic crude oil is a much lighter product than the heavy crude oil feedstock, and has no heavy-end components (molecules comprising a large number of carbon atoms). This last point is significant because even very light crude oils have at least a small fraction of heavy end components in their composition.

1.3 Methodology

The data, analysis, and results presented in this report are based on information available in the public domain. A prime difficulty encountered in a study covering this particular topic is the lack of publicly available, detailed, disaggregated data. However, given the data that are available, it is possible to evaluate directional impacts of various changes anticipated within heavy crude oil markets. Comments on resultant magnitude changes are restricted to identifying orders of magnitude.

Forecasts of supply and demand for heavy crude oil and refined petroleum products have been synthesized from comparisons of publicly available forecasts. In some cases comments and information from government and industry sources have been used to verify data and results.

1.4 Study Organization

The world oil market outlook and a discussion of crude oil price differentials are presented in Chapter 2. A discussion of market forces which influence the price differentials between light and heavy crude oils and a brief analysis of expected future pressures on differentials are presented.

Chapter 3 contains an overview of the historical data pertaining to Canadian and United States crude oil reserves, production, imports/exports and refining industries. Subject to the limitations imposed by data availability, data disaggregated by region and crude oil quality are presented for the historically important production and refining regions. The detailed data overview emphasizes heavy crude oil. The significance of heavy crude oil in the crude oil slate, changes over time in the composition of the slate, and variations in regional utilization patterns of heavy crude oil are highlighted.

Chapter 4 presents a synthesis of selected forecasts of the supply of, and the Canadian demand for, Canadian heavy crude oil. The synthesized supply and demand forecasts are then utilized to develop a forecast of the potential exportable volume of Canadian heavy crude oil.

Chapter 5 presents a synthesized forecast of the United States demand for Canadian heavy crude oil. This forecast is qualified by a discussion of the factors affecting the United States demand for Canadian heavy crude oil. The discussion includes an overview of the demand for asphalt; refinery configuration and utilization rates; competing sources of heavy crude oil supply; and trends in the quantity and composition of Canadian heavy crude oil imports. The major emphasis of the presentation is on the states situated in the Northeastern United States.

Chapter 6 discusses the question of diluent availability. An estimate of the volumes of diluent available for utilization in heavy crude oil pipelining is provided. This estimate is based on forecasts of expected diluent supply, and on a forecast of diluent requirements for other uses, such as refinery feedstock. A brief discussion is also given of alternative diluents, of alternatives to diluent, and of the pricing and regulation of diluents produced in Alberta.

An overview and concluding observations are presented in Chapter 7. The chapter commences with an illustrative netback calculation for the sale of selected Canadian heavy crude oils in several northern U.S. markets. Based on these calculations a number of observations are made with regard to the impact of price changes on the supply of, and the United States demand for, Canadian heavy crude oil. The impact of diluent availability and the cost of alternative diluents on the supply of and demand for Canadian heavy crude oil are also discussed. Data requirements for expanding the analysis to a comprehensive evaluation of the market potential for Canadian heavy crude oil are also provided.

A five section appendix volume is published under separate cover, and is available upon request.

Appendix A presents historical price differential data for selected international crude oils. This information, subject to data availability, is given for both spot and official prices. The forces impacting on historical differentials are analyzed in detail. In addition, a brief discussion of parity pricing is presented.

Appendix B provides detailed historical data on Canadian and United States refinery configurations and crude oil reserves, production, and disposition. There is considerable disaggregation of the data by region, crude quality, and time frame.

Appendix C contains the disaggregated forecast of Canadian heavy crude oil supply, Canadian refined petroleum products demand, and Canadian demand for Canadian heavy crude oil.

Appendix D includes detailed background data and discussion on the U.S. market interface for Canadian heavy crude oil.

Finally, Appendix E provides background and forecast data regarding pentanes plus diluent.

Footnotes

[1] Canada, National Energy Board, Canadian Energy Supply and Demand: 1980-2000 (Ottawa: Minister of Supply and Services Canada, 1981), Appendix J, p. 357. For a listing of the Canadian oil fields and pools that produce crude oil that is encompassed by this definition see Appendix B, pp. 237-238.

[2] API is an expression of the density or weight of a unit volume of material according to a scale developed by the American Petroleum Institute (API), and is used as a means of distinguishing between different types of crude. Lower API values indicate higher specific gravities and heavier crudes. Although many other characteristics differentiate between crudes (even those with the same API gravity), the API measure is generally utilized to differentiate between light, medium, and heavy crude oils.

Unfortunately, while API gravity is a commonly used measure, the range of values used to classify and distinguish between heavy and light crude oils is not. Thus, heavy crude oil is defined as being less than or equal to 25° API by the Energy Resources Conservation Board of Alberta, less than 18° API by the Saskatchewan Department of Energy and Mines, and about 31° API or lower by the world oil market in general. Such distinctions cause discrepancies in comparisons of production, reserves, and disposition data.

Discrepancies in definitions of heavy crude oil can also obscure the meaning of price differentials by comparing a variety of crude oils having very different API gravities. For example, world price differentials are generally based on the price difference between the Saudi light marker crude and other crudes, including, for example, Arab heavy which has an API of about 30°, a gravity generally associated in a Canadian context with a better quality medium crude oil.

Chapter 2

CRUDE OIL PRICE DIFFERENTIALS IN WORLD MARKETS

2.1 Introduction

Markets for Canadian heavy crude oil are linked to and affected by the world crude oil market with its supply, demand, and price levels. Specifically, the absolute world price level as well as the world price differential between crudes of various quality significantly impact U.S. refiners' demand for various crudes, including Canadian crude. Heavy crude oil demand is particularly sensitive to crude oil price differentials since the additional refining costs associated with such crudes could make their use as refinery feedstock uneconomic.

This chapter examines the forces that affect crude oil price differentials to highlight their potential impact on exports of Canadian heavy crude oil to the Northeastern U.S. market. First, historical official and spot market crude oil prices are reviewed with an emphasis on the latter due to the increasing share of crude transactions on the spot market. Historical refinery configurations worldwide are briefly outlined to illustrate the changing focus of this crude oil market sector. Refined petroleum products demand, refinery configuration and margins, and crude oil supply are then discussed as the three primary factors affecting crude oil price differentials. In particular, relevant factors are specified in each of these areas that would provide a viable export market in the U.S. for Canadian heavy crude oil. However, the complexity of these various forces and their interactions combined with inadequacies in available data preclude precise estimates of expected future differentials.

Because world crude oil markets are generally discussed using imperial units of measure (e.g., barrels as opposed to cubic metres), these measures are employed in this chapter, even though the remainder of the study is presented in metric units. Furthermore, the heavy crude oil statistics used in this chapter differ somewhat from those presented later in the study due to differing definitions of heavy crude oil. For example, Saudi Arabian Heavy has an average API gravity of 27°, a gravity normally associated with a medium crude, and other world "heavy" crudes have API gravities higher than 29° API, the limit used in the chapters to follow.

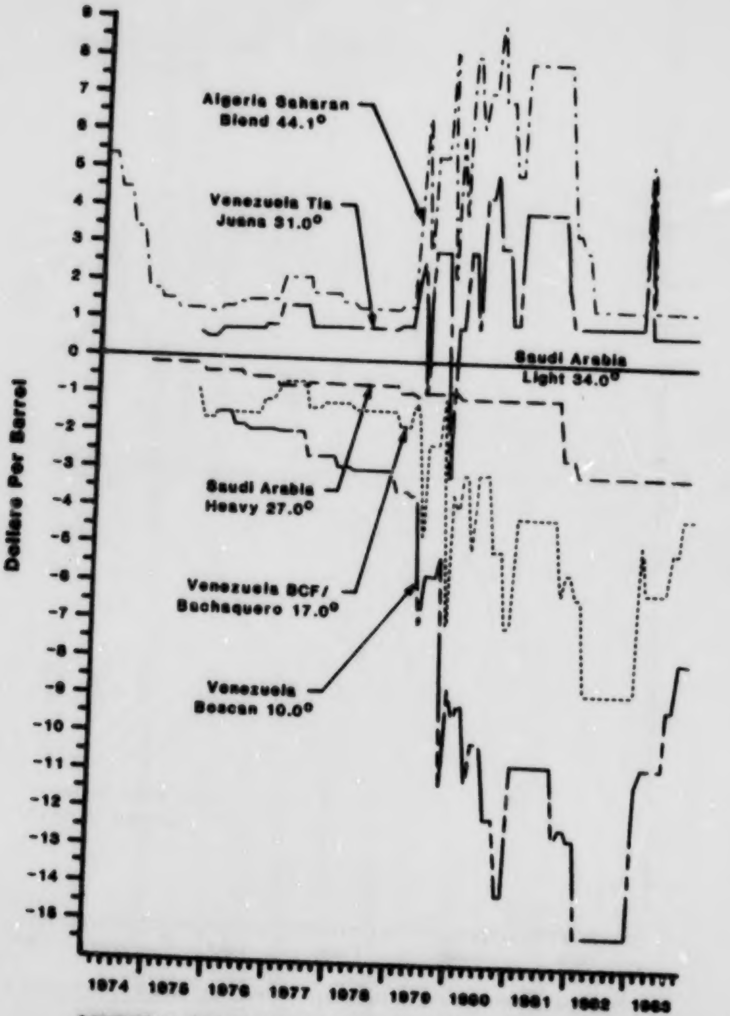
2.2 Review of Historical Crude Oil Price Differentials

All crude oils are not of equal value. The relative value of different crude oils to a refiner depends on a complex set of dynamic factors including oil supply/demand, refined product pricing, and product yield.[1] Producer yield depends on existing refinery configuration and operating conditions. Crude oil price differentials reflect the differing values of crudes of various qualities by indicating the price spread between higher and lower quality crudes.

Price differentials are not readily discernible from crude oil market data. Official posted price data are available but, since OPEC was established, official price differentials between various crudes have not always been representative of the true difference in market price. Alternatively, spot market prices provide a more accurate basis for comparing crude oils because they are responsive to the forces of supply and demand, product pricing, and refinery economics, and therefore more accurately reflect market conditions.[2] However, limited data are available on spot prices.

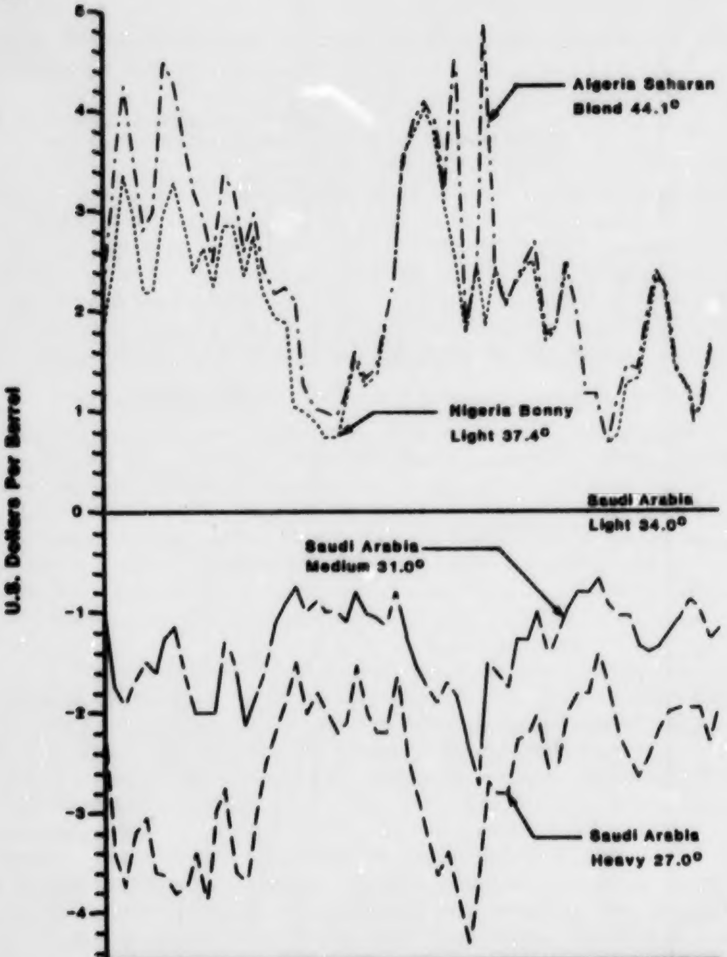
Figures 2.1 and 2.2 illustrate the differences between official and spot market crude oil price differentials. While the general trend in both is comparable, short-term fluctuations in spot market crude oil differentials are not always reflected in official crude oil price differentials. For example, the narrowing of spot differentials in 1980 is hardly noticeable in official differentials. Moreover, the overall narrowing trend in spot differentials as of 1982 is not generally seen in official differentials until early 1983. Finally, although official price changes by OPEC resulted in a wider range in official price differentials, official differentials are generally fixed and therefore more stable than spot market crude oil price differentials (see Table 2.1). Thus, spot market differentials are generally more indicative of true market conditions, and will therefore be the focus of this chapter.

Spot market crude oil prices have varied significantly both in long-term trends and short-term movements (see Figure 2.3). In general, spot market crude oil price differentials appear to widen in periods of relative price stability, while the prices for various



SOURCES: CERI calculations based on Petroleum Intelligence Weekly, various issues, and OPEC Annual Statistical Bulletin, 1982.

FIGURE 2.1: OFFICIAL PRICE DIFFERENTIALS FOR OPEC CRUDE OILS (SAUDI ARABIA LIGHT CRUDE 34° BASE): 1974-1982



SOURCES: CERI calculations based on Petroleum Intelligence Weekly, various issues, and OPEC Annual Statistical Bulletin, 1982.

FIGURE 2.2: OPEC SPOT MARKET PRICE DIFFERENTIALS FOR OPEC CRUDE OILS (SAUDI ARABIA LIGHT CRUDE 34° BASE): 1979-1984

TABLE 2.1

RANGE OF OFFICIAL AND SPOT MARKET CRUDE OIL PRICE DIFFERENTIALS

1976-1983[a]
($U.S./bbl)

Time Period[a]	1976-1977	1978-1979	1980-1981	1982-1983
Official Price Differentials[b]				
Algerian Light/Venezuelan Heavy[c]	2.85-4.15	4.40-14.60	15.81-18.60	12.10-16.60
Algerian Light/Saudi Arabian Heavy[d]	1.18-2.07	1.36- 3.88	3.63- 7.33	3.67
Spot Market Price Differentials				
Algerian Light/Saudi Arabian Heavy[d]	NR	6.30- 7.90	4.90- 6.70	3.20- 5.00
African Light/Mideast Light	NR	NR	1.95- 5.00	1.80- 4.21

SOURCES: (1) OPEC Annual Statistical Bulletin 1982, Table 109; and (2) CERI calculations based on Petroleum Intelligence Weekly, various issues.

[a] Selected periods based on available data.
[b] Official crude oil selling prices in country of origin, f.o.b. loading ports.
[c] Extra light/sweet Algerian crude oil compared with extra heavy/sour Venezuelan Boscan crude oil.
[d] Algerian Saharan light crude oil compared with Saudi Arabian heavy crude oil.

SOURCES: CERI calculations based on Petroleum Intelligence Weekly, various issues, and OPEC Annual Statistical Bulletin, 1982.

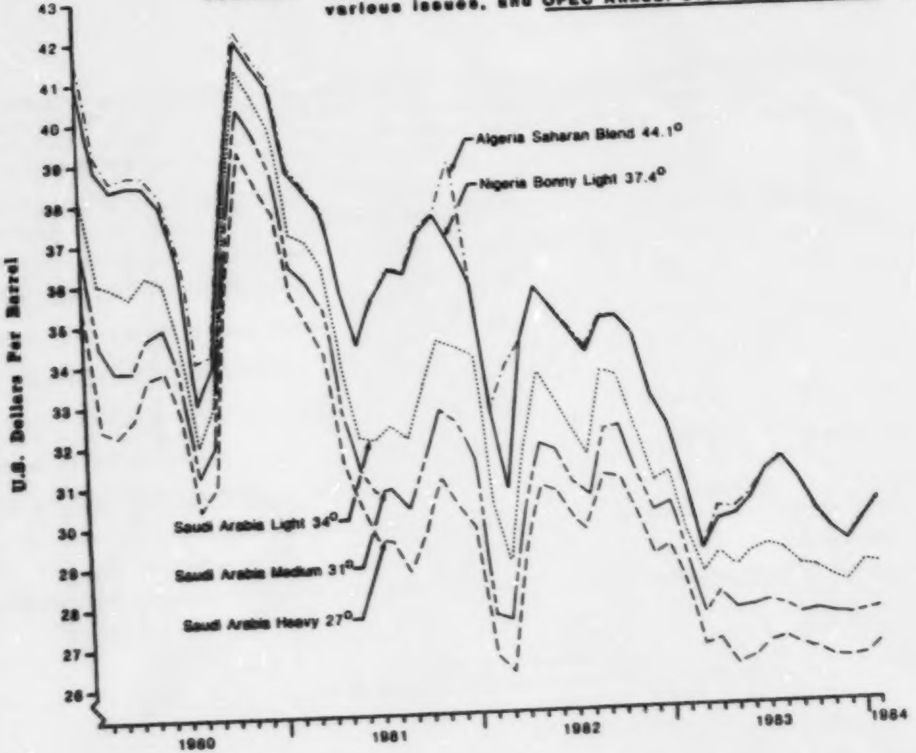


FIGURE 2.3: SPOT MARKET PRICES FOR OPEC CRUDE OILS: 1980-1984

grades of crude parallel each other more closely during times of overall price increases or decreases.

2.3 World Oil Market Review and Outlook

The world oil market has undergone considerable change since the first major oil price increase in 1973. Despite the quadrupling of prices, crude oil consumption continued to increase throughout the remainder of the 1970s. However, supply disruptions, the Iranian crisis, and the subsequent doubling of oil prices from 1979 to 1980 caused an overall decrease in crude oil consumption of 11 percent over the period 1979 to 1983.[3] The contraction in demand was both structural and cyclical. A significant portion of the decline was due to conservation and substitution measures induced by sharply higher prices. This decline in demand altered market structure such that this portion of demand is not expected to return during economic recovery. The remaining portion of the decline in demand was cyclical decline due to recession, and is therefore expected to rebound with economic recovery.

On the supply side, OPEC production fell from 31.5 million barrels per day in 1979 to 18.3 million barrels per day in 1983, just over its official overall production quota of 17.5 million barrels per day. In contrast, non-OPEC (non-Communist) production has been rising moderately by about 4 percent per year since the mid-1970s, such that in early 1983, non-OPEC production surpassed OPEC output.[4] OPEC has become the supplier of last resort and now supplies less than half of the non-Communist world's crude oil.

Large surplus productive capacity now exists worldwide, primarily within OPEC. As a result, OPEC lowered the price of its Saudi Arabia light benchmark crude by $5 per barrel in March 1983. Barring a major supply disruption, no real increases in oil prices are expected for the remainder of the 1980s. In fact, prices are expected to remain fairly stable in the short term near the official benchmark level of $29 per barrel (U.S.)[5] which will result in lower real prices. Moreover, at the end of the Iran/Iraq war significant volumes of crude could come onto the market, and cause downward pressure on prices. On the other hand, upward pressure on prices is possible should the Persian Gulf be closed for any extended period.

Renewed economic growth and relatively low oil prices are expected to induce an increase in oil demand, although at lower rates of growth than in previous decades (see Table 2.2). Demand is expected to increase at an average annual rate of 1.3 percent from 1984 to 2000.

Supply is expected to increase correspondingly, with the current surplus in production capacity declining in the 1990s. Non-OPEC supply is not projected to change significantly to 2000, but OPEC production is expected to increase steadily through the remainder of this decade and the 1990s.

2.4 Overview of the Factors Affecting Crude Oil Price Differentials

The possible impact of these trends in terms of differentials must be examined in light of the various factors affecting them. Assessing these factors is a difficult and complex undertaking due to the many factors that can influence differentials all along the processing chain, from crude production through to the final demand for refined petroleum products. Linkages between these factors and differences in short-term and long-term impacts make it difficult to determine the net impact of a given change in one or more factors. To simplify matters somewhat, the following discussion has been broken down to examine the relevant factors at the refinery and then the market level.

2.4.1 Micro Level Analysis

The issue of differentials can be examined from both a micro and a macro viewpoint. At the micro level, the value of particular crudes to individual refiners must be assessed. A refiner has several options when selecting crudes to satisfy different sets of product slates:

- select a higher quality crude and process lighter, higher value products,
- select a lower quality crude and upgrade it into lighter, higher value products, or
- select a lower quality crude and process lower quality, lower value products.

TABLE 2.2

WORLD CRUDE OIL SUPPLY/DEMAND OUTLOOK
(MMb/d)

	1984	1990	1995	2000
Demand	45.5	49.8	52.3	55.6
Supply				
Crude Oil				
Non-OPEC[a]	22.2	22.7	23.0	22.5
OPEC	18.2	22.1	24.6	26.8
NGLs				
Non-OPEC	2.4	2.5	2.5	2.5
OPEC	1.0	1.5	1.7	1.8
CPE Exports[b]	1.8	1.0	0.5	-
Total Supply	45.6	49.8	52.3	53.6

SOURCES: CERI calculations based on the following sources: (1) Conoco Coordinating and Planning Department, Conoco Inc., "World Energy Outlook Through 2000" (Wellington, Delaware: Conoco Inc., 1984); (2) International Energy Agency, Organization for Economic Co-operation and Development, World Energy Outlook (Paris, France: OECD Publications, 1982); and (3) United States Energy Information Administration, Annual Energy Outlook 1983 (Washington D.C.: U.S. Government Printing Office, 1984).

[a] Includes refinery gain.

[b] Centrally planned economies, including European and non-European Comecon countries.

This decision is made subject to prevailing constraints and market conditions including:

- the individual refinery's configuration,
- product yields (ranges) for individual process units,
- processing costs,
- refined petroleum product demand,
- product prices,
- available crude streams by volume and price, and
- assays for the available crude oil streams.

The optimal tool for assessing the value of refined crudes is a linear programming model (LP) of specific refinery configuration(s). LP models are used by most refineries to optimize refinery operations because they allow for substitution possibilities between crudes and processes, joint inputs and outputs, physical refinery constraints, and differing product costs/prices. Direct operating costs for processing a barrel of crude oil are identified and required price differentials can be assessed for refining specific crudes in a given refinery configuration with a specified product slate.

2.4.2 Macro Level Analysis

The LP evaluation of crude oils provides a method for analyzing price differentials in a specific location at a point in time, but does not describe the dynamic nature of the refining industry and crude oil markets. A generalized LP model could be developed to indicate regional bottlenecks and constraints, and supply and surpluses that would identify pressures on differentials based on current and expected market conditions. In particular, the model would include the main factors affecting crude oil price differentials: product markets, refining capacity, and crude oil supply.

Various other factors impact on each of the above factors. Changes in product demand, shifts in the quality of refined products, and the linkages to overall energy demand and prices are important factors in product markets. Within the refining industry, changes in overall capacity, especially in new upgrading equipment, are most significant. Finally, crude oil supply is affected by current production and recovery technology, production costs, and logistical constraints.

All of the aforementioned factors are themselves affected by crude oil price differentials. Nevertheless, the focus here is on their impact on differentials. Thus, the interaction between each of these factors and differentials is outlined below. In addition, the expected future trends for each factor and the corresponding impact on differentials is also discussed. Appendix A provides an historical review of these factors.

2.5 Factors Affecting Crude Oil Price Differentials

2.5.1 Refined Petroleum Products Demand

The demand for refined petroleum products is fundamentally linked to the entire processing chain, including pricing, overall energy demand, crude supply, and refining operations. Changes in product demand can directly affect differentials by fluctuations in absolute and relative levels of demand. Nevertheless, the net impact on differentials depends on changes in other factors, including levels of overall oil demand, available crude supplies, and refinery flexibility. For example, a shift toward lighter products when overall oil demand is rising would tend to increase differentials. On the other hand, a demand shift from heavy to light products in a market where overall oil demand is falling could result in lower light crude prices and differentials if the net effect was a decrease in light crude oil demand.

Prices for petroleum products are directly associated with product demand and can greatly affect refining operations. A narrowing of prices between light and heavy products (e.g., gasoline/distillates and residual fuel oil) could be caused by relatively low light product prices and/or relatively high heavy product prices. Low light product prices could result from falling demand and/or surplus production. Residual fuel oil prices could be high because of lower resid production (due to refinery closures and new upgrading capacity) or by a rebound in demand (increased economic growth or substitution for other fuels).

Future demand patterns for individual refined petroleum products will be a major determinant of crude oil price differentials. In general, product demand is anticipated to increase with the general increase in economic activity. While demand projections for individual refined petroleum products (RPP) vary from region to region, the general outlook is for a continual "lightening" of RPPs as gasoline and middle distillates demand increases relative to fuel oil.[6] As the demand for light products increases relative to heavier ends, light crude demand will tend to increase, and crude oil price differentials could widen.[7]

Alternatively, the future refined product demand mix may not become appreciably lighter if either residual fuel oil (RFO) demand increases more than generally expected, or light product demand growth is significantly lower than expected. RFO demand is the most difficult to forecast since it is essentially a by-product of refining and competes with several other fuel sources in the industrial market.[8] In recent years, RFO has lost significant market share to other fuels and this trend is generally expected to continue. Alternative fuels have been displacing RFO due to energy policies in consuming nations which restrict RFO use in anticipation of a worldwide shortage of oil. However, if future energy policies remove the RFO bias and/or new alternative supplies do not develop, or are higher priced than anticipated, RFO demand could increase.

The growth in light product demand may also not be as strong as projected. Gasoline demand could be further reduced by higher vehicle fuel efficiencies, changes in driving habits, or alternative fuel substitution. Slower light product demand growth or higher than expected levels of RFO demand could leave differentials unchanged.

2.5.2 Refining Capacity

Refining is at the centre of the processing chain and petroleum markets in general. It is impacted by changes in both the crude oil and petroleum product markets, and in turn impacts developments in both of these sectors. Refinery configuration establishes at any point in time the capability and flexibility in producing a given slate of products from certain grades of crudes. In the short term, substitution between the quality of crude feedstocks used by refineries will impact on crude oil price differentials, while long-term impacts will come from investment in additional or more flexible capacity.

Refining capacity investment decisions are largely a function of utilization rates and refining margins. Changes in refining capacity generally take two forms:

- scrapping inefficient uneconomic refineries, and
- investing in new upgrading capacity (either through retrofitting or new grassroots refineries).

Falling product demand, lower product prices, and shrinking refining margins could all result in the closure of marginal refineries. On the other hand, upgrading capacity is required as the demand for petroleum products shifts from heavy to light, and/or the average quality of crude supply becomes heavier.[9]

The primary link between crude price differentials and investment in new or upgrading capacity is the impact on crude oil demand. An increase in capacity may not affect differentials per se, but a relative increase in the demand for either light or heavy crude could affect differentials. For example, new upgrading capacity could increase heavy crude oil demand and prices and thereby narrow crude oil price differentials.[10]

The refining industry in the U.S. and Europe has contracted in recent years due to the reduction of oil demand, the shift in demand from heavy to light products, and low or negative margins. Further closures are likely, especially as new upgrading capacity is scheduled to come on stream.

The U.S. currently has about half of the world's upgrading capacity, and is expected to account for about one-quarter of the growth to 1990 (see Table 2.3). Europe remains the second largest upgrading centre and is expected to account for over 20 percent of the new upgrading capacity.

According to a study by Petroleum Industry Research Associates and Chem Systems, "some time after 1985, further declines in residual fuel oil demand and a heavier crude slate will again place pressure on North and South American refinery systems to install bottoms upgrading. Other world areas will be able to satisfy demands through 1995 without significant residuum destruction."[11]

The Middle Eastern refining industry accounts for 12 percent of projected world upgrading capacity additions with total OPEC vacuum distillation capacity increasing 21 percent from 1985 to 1988 to 2.3 million barrels per day, and total cracking capacity increasing 34 percent to 1.5 million barrels per day.[12]

TABLE 2.3

WORLD HEAVY CRUDE OIL REFINERY UPGRADING CAPACITY AND PROJECTED ADDITIONS AS OF 1984

	Current Capacity			Capacity Additions[a]		
	Input Capacity		Light Product Yield[b]	Input Capacity		Light Product Yield[b]
	(MMb/d)	(%)		(MMb/d)	(%)	
Africa	0.13	1.4	61.9	0.15	3.0	46.7
Canada	0.45	3.9	77.6	0.28	5.7	89.3
Europe	1.66	20.5	54.2	1.02	20.7	58.8
Far East	0.44	5.1	57.9	0.46	9.3	63.0
Japan	0.40	3.5	76.9	0.58	11.8	70.7
Latin America	1.05	11.6	60.3	0.53	10.8	64.2
Middle East	0.31	3.1	66.0	0.60	12.2	71.7
U.S.	5.96	50.9	78.4	1.30	26.4	75.4
Total	14.94	100.0	69.6	4.92	100.0	68.5

SOURCE: Petroleum Intelligence Weekly, April 16, 1984, p. 6.

[a] Projected additions to upgrading capacity, 1984 to 1990.
[b] Light product yield as a percentage of total input capacity.

These projected capacity additions support projections that OPEC refined product exports will reach over 4 million barrels per day by the mid-1980s which could amount to 15 percent of world oil trade (see Table 2.4). This increase in world product supply will place downward pressure on product prices, undermining the price of crude, and therefore could also affect crude differentials. Moreover, if the products are sold at prices linked to the spot market as products from existing refineries currently are, "under current market conditions... it would be cheaper to buy a barrel of products from these refineries than to buy a barrel of crude and refine it. That is not the way to maintain official prices for crude oil,"[13] or official differentials.

According to the Chase Manhattan Bank, total world heavy oil upgrading capacity is projected to increase over 30 percent by 1990 (see Table 2.5). This increase has been generally attributed to projected declines in overall crude oil quality. Nevertheless, the average API gravity of crude oil feedstock is expected to fall only half a degree from 1984 to 1990 bringing the importance of upgrading additions into question. Moreover, total upgrading capacity currently exceeds upgrading requirements and is expected to continue as such until 1990.

These capacity additions could narrow crude oil price differentials by increasing the demand for heavy crude oil relative to light crude oil. However, if much of these capacity additions do not actually occur, or are latent due to low upgrading requirements, crude differentials may not be greatly affected.

2.5.3 Crude Oil Supply

Changing crude oil supply is another important factor affecting crude oil price differentials. In addition to changes in the absolute volumes of light and heavy crudes, changes in the average quality of crude oil production will affect differentials, and the processing/investment decisions made by refiners. The effects of changes in the reserve base and the productive capacity of various quality crudes must be viewed in the context of crude oil demand by refiners. In general, a shortage of heavy crude will cause the differential between heavy and light crudes to narrow, and a surplus will cause it to widen.[14] Conversely, a shortage of light crude tends to widen differentials, while a surplus narrows differentials.

TABLE 2.4

ESTIMATED DISPOSITION OF OPEC PRODUCTION

	Volume (MMb/d)				% of Crude & NGL Production				% of World Oil Trade			
	1975	1980	1983	1986	1975	1980	1983	1986	1975	1980	1983	1986
Crude Oil Exports	23.6	22.4	10.9	12.3	85.5	80.6	60.9	56.7	77.9	70.2	45.4	45.2
Product Exports	2.1	2.3	3.1	4.1	7.6	8.3	17.3	18.9	6.9	7.2	12.9	15.1
NGL Exports	0.4	0.8	0.7	1.5	1.4	2.9	3.9	6.9	1.3	2.5	2.9	5.5
Domestic Consumption	1.5	2.3	3.2	3.8	5.4	8.3	17.7	17.7	NA	NA	NA	NA
Total Crude Oil and NGL Production[a]	27.6	27.8	17.9	21.7	100.0	100.0	100.0	100.0	NA	NA	NA	NA

SOURCE: Petroleum Intelligence Weekly, September 12, 1983, p. 9.

[a] Includes NGL production amounting to 0.4, 0.9, 0.9, and 1.7 million barrels per day in 1975, 1980, 1983 and 1986, respectively.

TABLE 2.5

WORLD HEAVY OIL CONVERSION CAPACITY AND REQUIREMENTS
1984-1990
(MMb/d)

	1984	1986	1988	1990
Crude Throughput	39.4	41.2	42.6	44.1
Upgrading Requirements	9.0	10.0	10.9	11.5
Upgrading Capacity[a]	10.4	11.4	12.4	13.8
Upgrading Utilization (%)	86.5	87.7	87.9	83.3
Average Crude Gravity (°)	32.3	32.2	32.0	31.7

SOURCE: Petroleum Intelligence Weekly, April 16, 1984, p. 6.

[a] Effective capacity (amount of light products yield generated by overall configuration of upgrading units).

As previously mentioned, future world crude oil supplies will become increasingly heavy, particularly once OPEC production levels begin approaching capacity in the late 1980s. While most of the increased production will come from OPEC, new production from Western Hemisphere sources will generally also be heavier grade crude oils.

In the U.S., for example, Alaska North Slope (ANS) production with an average API gravity less than 27° has been a significant new source of supply since 1977. The percentage of ANS to total U.S. production is expected to increase from 15 percent in 1983 to 17 percent in 1990, and only 13 percent in 1995.[15] This, combined with heavy offshore California crude oil from the outer continental shelf (OCS), which is also expected to be a major new source of supply by the late 1990s, will contribute to the decline in average crude quality in the U.S.[16]

Venezuela, Canada, and Mexico together contain over 57 percent of the world's heavy, extra heavy, and bitumen reserves but only 10 percent of the world's conventional oil reserves. New export supplies from these countries are likely to be increasingly heavy, particularly once demand for conventional light crude oil approaches capacity levels. Canadian reserves and production potential will be further discussed in Chapters 3 and 4.

Thus, new sources of Western Hemisphere crude oil production are expected to be heavier than in the past and will eventually cause the overall world supply mix to be heavier. This projected increase in heavy crude supply will put downward pressure on heavy crude prices and could cause crude oil price differentials to widen. The extent of this will obviously also depend on corresponding changes in light crude oil supply. The net effect on differentials will depend on changes in the relative proportion of heavy and light crude supply to total supply.

2.6 Outlook for World Crude Oil Differentials

In light of the context of our study, Canadian heavy crude production would be encouraged by what will be subjectively termed a "strong" crude market, i.e., one that is profitable from a refiner's point of view, including a wide crude oil price differential. This market could be characterized by the following:

- rising energy demand
- stable energy prices
- rising demand for light products
- wide refined product price differentials
- adequate refining capacity, including upgrading capacity
- high refinery utilization rate
- wide refining margins
- no excessive surpluses or shortages of light or heavy oil
- wide oil price differentials

Alternatively, the current market may be characterized as a "weak" market and, as such, includes the following:

- weak, unstable energy demand
- weak, unstable energy prices
- weak demand for light products
- weak light product prices
- firm heavy product prices
- narrow refined product price differentials
- surplus refining capacity
- low utilization rates
- low refining margins
- increases in upgrading capacity
- decrease in residual fuel oil production
- surplus light crude productive capacity
- reduced OPEC production
- reduced heavy crude production
- weak OPEC pricing policy regarding differentials
- narrow crude oil differentials
- increase in OPEC downstream refining capacity

To transform the current market from weak to strong, the key driving force would be an increase in the demand for light products which would increase the price spread between light and heavy products, improve refining margins for light products, raise the demand for light crudes, and widen crude oil price differentials. Similarly, a shortage of upgrading capacity could result in wider and crude oil price differentials by decreasing the demand for heavy crude oil. Finally, changes in the availability of crude supplies relative to demand will also impact differentials. A surplus of heavy crude relative to light will tend to widen differentials and create a strong market. Table 2.6 summarizes these factors and their effect on differentials.

TABLE 2.6

FACTORS AFFECTING DIFFERENTIALS

	Product Markets	Refining Capacity	Crude Supply
Strong Market	- rising energy demand and stable prices - rising demand for light products - wide price differentials between light and heavy refined products	- adequate refining capacity, including upgrading capacity - high utilization rate - wide refining margins	- adequate supplies of light and heavy oil relative to demand (i.e., no excessive surpluses or shortages) - wide oil price differentials
Weak Market (Current Market)	- weak, unstable energy demand and prices - weak demand and prices for light products - firm heavy product prices - narrow product price differentials	- surplus refining capacity - increase in OPEC downstream refining capacity - increases in upgrading capacity - low utilization rate - low refining margins	- low heavy crude and residual fuel oil production - surplus light crude production capacity - narrow crude oil price differentials and weak OPEC policy regarding differentials
Changes to Move From Weak to Strong	- increased demand for light products - overall increase in energy and oil demand	- decreased refining capacity - decreased production of light products - increased production of residual fuel oil	- increased heavy crude production relative to light
Results of Changes	- wider differentials between light and heavy crude products	- wider differentials yielding wider refining margins	- wider differentials between light and heavy crude oil

SOURCE: CERI.

2.7 Summary

Crude oil price differentials are an important factor affecting the development of heavy crude oil reserves. Relatively wide differentials encourage heavy crude oil upgrading, thereby increasing demand, and exploration and production activity. However, limited historical data on both official and spot market crude oil price differentials provide no clear pattern or trend, and no methodology for projections. Refined products demand, refinery capacity, and crude oil supply all impact on crude oil price differentials. However, the interaction between these variables is complex, and projections regarding their own future directions are varied such that the net impact on differentials can only be identified in terms of directional changes. Further analysis based on more and, in some instances, confidential data with emphasis on trends in product demand, refinery capacity, and crude supply patterns would be necessary for an actual forecast of differentials. In general, crude oil price differentials are expected to narrow in the short term due to excess supply of light crude oil and increasing demand for heavy crude oil as refinery capacity for the latter increases. In the long term, differentials are expected to widen as the supply of light crude oil ultimately declines relative to heavy crude oil.

In the short term, differentials are probably of lesser importance to a refiner than are the absolute and relative prices of competing sources of heavy crudes. These will largely be determined by the supply and demand of heavy crude oil. Chapter 3 provides an historical overview of Canadian and U.S. heavy crude oil supply and demand.

Footnotes

[1] "How Price Differentials Affect Refinery Upgrading," Petroleum Intelligence Weekly, May 7, 1984, p. 7.

[2] Moreover, while "the London futures [market] assessors are going to look at spot markets, official prices and netbacks, and other indicators in setting differentials...the primary differential indicator will be the spot crude market." See "Price Differentials, a Thorny Issue for London Oil Futures," Petroleum Intelligence Weekly, October 31, 1983, p. 7.

[3] The British Petroleum Company, BP Statistical Review of World Energy, June 1984, p. 7.

[4] Ibid., p. 5.

[5] "Oil Prices: Living with the Perils of Prophecy," Petroleum Intelligence Weekly, December 3, 1984, p. 7.

[6] "How Price Differentials Affect Refinery Upgrading," Petroleum Intelligence Weekly, May 7, 1984, p. 7.

[7] "Surge of U.S. Refinery Upgrading Trims Heavy Feed, Boosts Prices," Oil and Gas Journal, April 30, 1984, p. 21.

[8] "Glut of Residual Fuel Seen Looming for Pacific Basin," Petroleum Intelligence Weekly, December 12, 1983, p. 7.

[9] "Surge of U.S. Refinery Upgrading Trims Heavy Feed, Boosts Prices," Oil and Gas Journal, April 30, 1984, p. 20.

[10] "How Price Differentials Affect Refinery Upgrading," Petroleum Intelligence Weekly, May 7, 1984, p. 8.

[11] "World Resid Supply Seen Tightening," Oil and Gas Journal, August 8, 1983, p. 65.

[12] "OPEC States Plan Big Rise in Capacity to Upgrade Products," Petroleum Intelligence Weekly, October 31, 1983, p. 8.

[13] Dr. Tor Meloe, "World Oil Markets: Post-October Assessment," paper presented to the International Association of Energy Economists Annual Meeting, San Francisco, California, November 5-7, 1984, p. 12. The December 24, 1984 edition of Petroleum Intelligence Weekly reported per barrel refined product prices of $25 in the U.S., and $25.50 in Europe, both well below the $29 per barrel price for the Saudi Arabian light market crude.

[14] "How Price Differentials Affect Refinery Upgrading," Petroleum Intelligence Weekly, May 7, 1984, p. 8.

[15] United States Energy Information Administration, Annual Energy Outlook 1983 (Washington, D.C.: U.S. Government Printing Office, 1984), Table A15, p. 202. Projections for the mid-price case (given) and the low price case are comparable, while the high price case projections for 1990 and 1995 are 15 percent and 11 percent, respectively.

[16] "Surge of U.S. Refinery Upgrading Trims Heavy Feed, Boosts Prices," Oil and Gas Journal, April 30, 1984, p. 20.

Chapter 3

REVIEW OF HISTORICAL HEAVY CRUDE OIL DATA

3.1 Introduction

This chapter presents an historical overview of heavy crude oil production, reserves, and refining data for Canada and the United States. Historical market trends that have affected the development of Canadian reserves of heavy crude oil are also identified. The data required for a complete analysis of the market potential for Canadian heavy crude are listed and contrasted with the available data. Inadequacies in both Canadian and U.S. data regarding refinery deliveries and classification of heavy crude oil production and reserves by API gravity limit the conclusions that may be drawn. However, the information presented in this chapter does provide a basis for the analysis presented in the subsequent chapters.

3.2 Review of Heavy Crude Oil Data

Some indication of the future supply/demand balances of heavy crude markets may be drawn from an analysis of historical market data. Crude oil production and remaining recoverable reserves may be used to infer short-term and long-term supply levels, respectively.[1] Crude disposition and refinery configuration provide some indication of actual and potential demand. (These elements will be reviewed in the next section for both Canada and the United States.) Data limitations, especially the lack of disaggregated crude oil disposition data, preclude precise estimates of heavy crude oil market balances. However, some limited conclusions may be drawn from the available data.

One particular problem encountered in the analysis was the variation in definitions of heavy crude oil. In this chapter and the accompanying appendices, Canadian heavy crude oil includes heavy crude as defined by the Alberta Energy Resources Conservation Board (generally less than 25° API), and heavy and medium crude as defined by the Saskatchewan Department of Energy, Mines and Resources (generally less than or equal to 17° and 29° API, respectively). Data provided by

Energy, Mines and Resources Canada includes crudes less than 30° API. These definitions are further obscured in that heavy crude oil pipeline streams are sometimes used for data collection, even though limited volumes of light crude are sometimes included. As concluded in Chapter 1, these distinctions will be mentioned wherever possible in the tables, but the data will generally be treated as comparable.

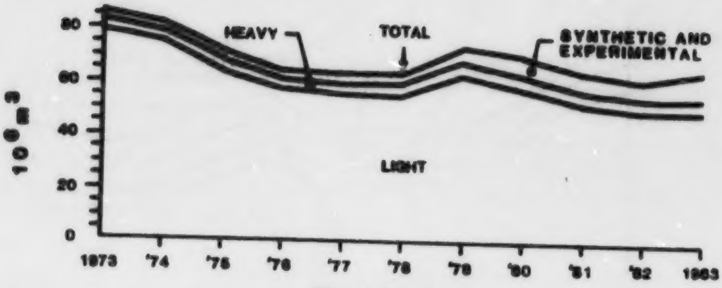
3.2.1 Canadian Heavy Crude Oil Production

Since 1973 Canadian crude oil production has exceeded 70 million cubic metres, 5 to 10 percent of which was heavy crude (see Figures 3.1 and 3.2 and Table B.1). The proportion of heavy crude to total production has almost doubled since 1973 due to an increase in heavy oil production combined with a decline in total production. Alberta accounts for 84 percent of Canada's total 1983 crude production, and Saskatchewan for 12 percent. Sixty percent of 1983 Canadian heavy crude production was from Alberta, with Saskatchewan accounting for the other 40 percent.

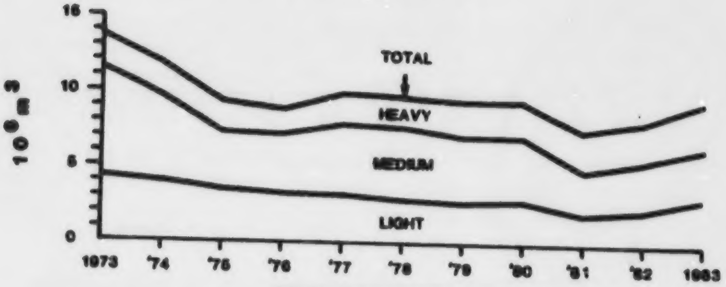
Alberta's crude oil production consists mainly of the lighter and medium grade crudes, with heavy oil representing about 7 percent of Alberta's total 1983 production. Since 1967 Alberta has also produced a small amount of synthetic crude. This amount has increased such that synthetic crude accounted for about 14 percent of Alberta's total crude production in 1983.

Saskatchewan is Canada's second largest producer of crude oil, but is a relatively small producer compared with Alberta. Light crude oil production has accounted for over one-quarter of Saskatchewan's output since 1981, with medium and heavy oil making up the remainder. Saskatchewan's total crude oil production has represented over 10 percent of Canada's total production for the past ten years.

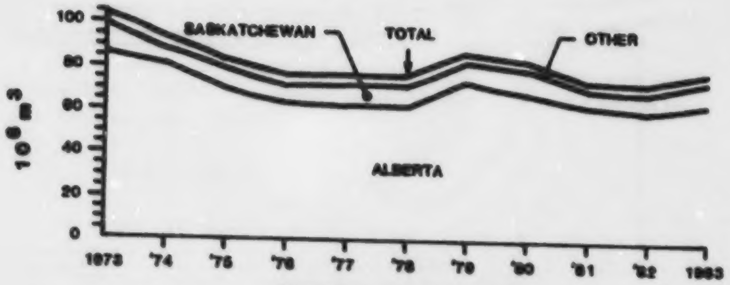
In general, Canadian crude oil production is declining both regionally and overall. Total Canadian output has fallen some 25 percent since 1973, with slight increases and decreases occurring throughout the period. Consistent increases have occurred only in synthetic and experimental production, but their contribution to the total is relatively insignificant. The 40 percent increase in heavy oil production with its correspondent increase from 5 to 10 percent of total Canadian production is far more significant.



Alberta Production



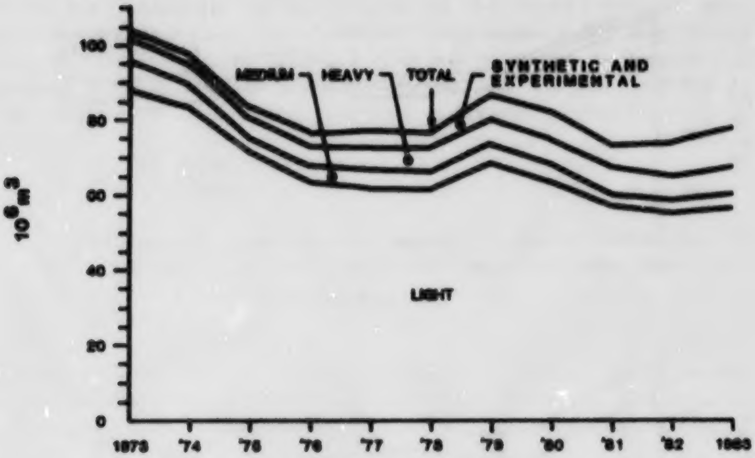
Saskatchewan Production



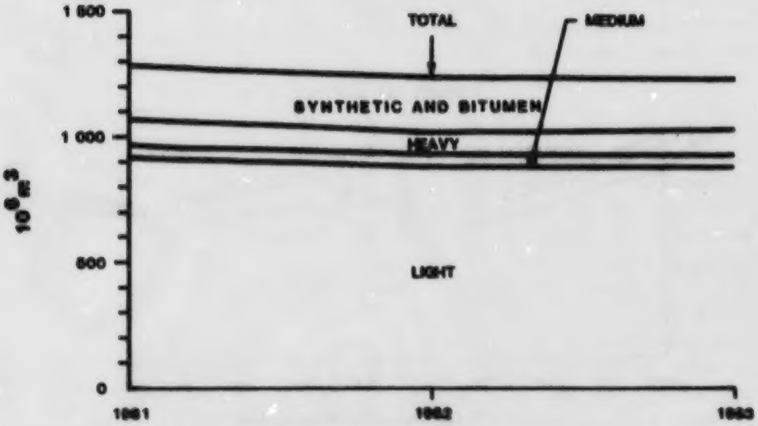
Total Canadian Production

SOURCE: Table 3.1.

FIGURE 3.1: CANADIAN CRUDE OIL PRODUCTION: 1973-1983



Production



Remaining Established Recoverable Reserves

SOURCES: Tables B.1 and B.2.

FIGURE 3.2: CANADIAN CRUDE OIL PRODUCTION, 1973-1983, AND REMAINING ESTABLISHED RECOVERABLE RESERVES, 1981-1983

3.2.2 Canadian Heavy Crude Oil Reserves

Canada's heavy crude reserves are extensive, but are concentrated in a relatively small area in Alberta and Saskatchewan. Figure 3.3 presents major Canadian heavy oil and oil sands areas. Despite the relatively close proximity of these deposits, their characteristics in terms of API gravity and sulphur content vary considerably. The API gravity ranges from 10° to 32° API, the sulphur, from 1.7 to 4.7 percent by weight (see Table 3.1).

As of December 31, 1983 Canada had over one billion cubic metres of crude oil remaining recoverable reserves and an additional 0.2 billion cubic metres of synthetic crude and bitumen remaining recoverable reserves (see Figure 3.2 and Table B.2). Alberta and Saskatchewan accounted for 71 and 9 percent of total reserves, respectively. Three-quarters of the remaining 20 percent was East Coast offshore light crude reserves.

Alberta's remaining established reserves declined between 1981 and 1983 despite slight increases in both medium and heavy crude reserves. Saskatchewan's situation was similar, but showed an increase in remaining established reserves of heavy crude only.

Overall, these trends suggest that Canadian crude oil production will depend increasingly on Canada's reserves of heavier crudes. It is significant that remaining established reserves of heavy crude have increased despite the fact that heavy crude production was increasing over the same period. Improved technology and higher oil prices have enabled the development of Canada's non-conventional and more inaccessible reserves.

3.2.3 U.S. Crude Oil Production

Crude oil production in the United States totalled 502 million cubic metres in 1982, with some 80 percent of that production coming from Petroleum Administration for Defence (PAD) Districts III and V (see Figure 3.4 and Table B.3). Figure 3.5 depicts the U.S. divided into its various PAD districts. PAD District II had the third highest crude oil production in the U.S., but only accounted for 12 percent of the total. By comparison, total Canadian crude oil production was 74 million cubic metres for the same time period.

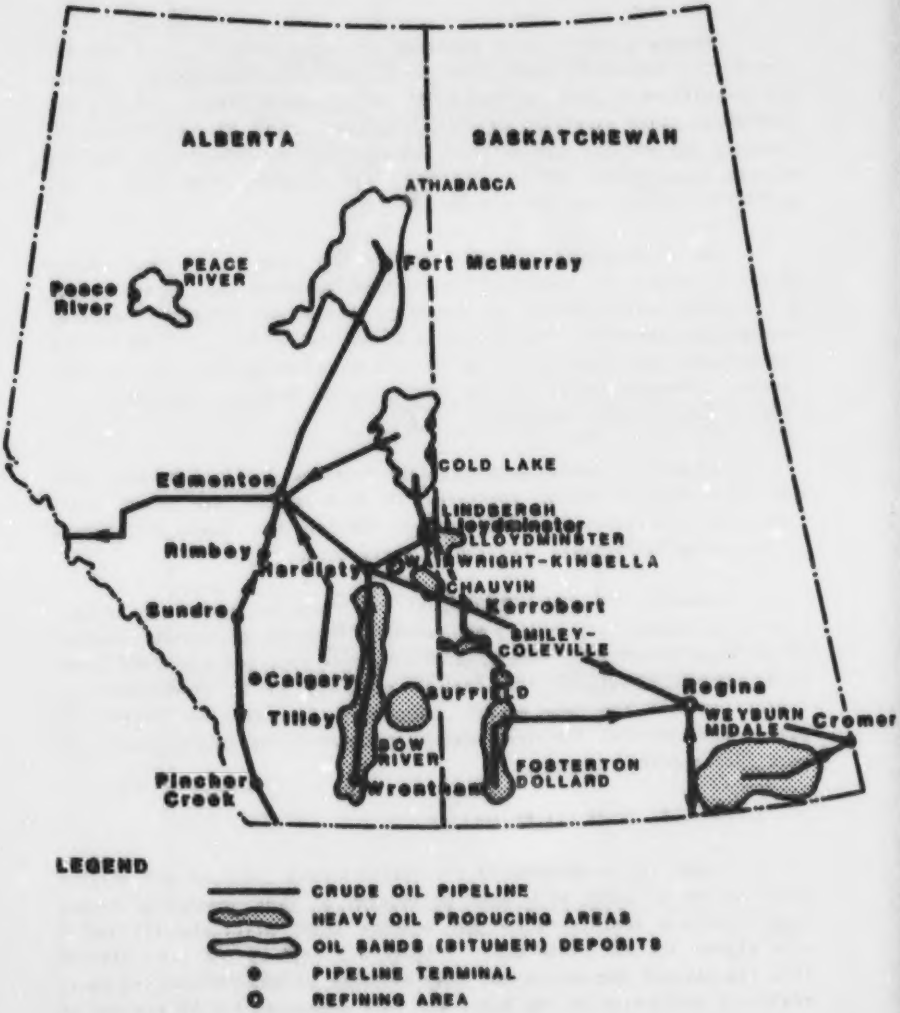

ALBERTA
SASKATCHEWAN
ATHABASCA
Fort McMurray
PEACE RIVER
Peace River
COLD LAKE
Edmonton
LINDBERGH
Lloydminster
LLOYDMINSTER
WAINWRIGHT-KINSELLA
Rimbey
Hardisty
CHAUVIN
Kerrobert
Sundre
SMILEY-COLEVILLE
Calgary
SUFFIELD
Regina
Tilley
WEYBURN MIDALE
Cromer
BOW RIVER
FOSTERTON DOLLARD
Pincher Creek
Wrentham
LEGEND
CRUDE OIL PIPELINE
HEAVY OIL PRODUCING AREAS
OIL SANDS (BITUMEN) DEPOSITS
PIPELINE TERMINAL
REFINING AREA

FIGURE 3.3: MAJOR HEAVY OIL AREAS IN WESTERN CANADA

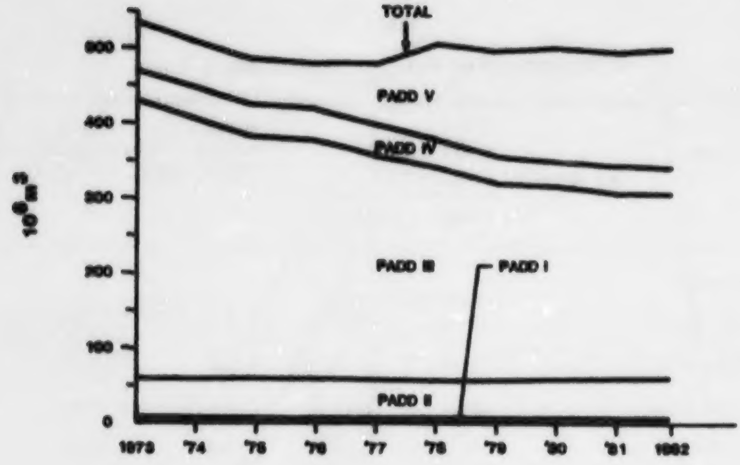
TABLE 3.1

CHARACTERISTICS OF WESTERN CANADIAN HEAVY CRUDES

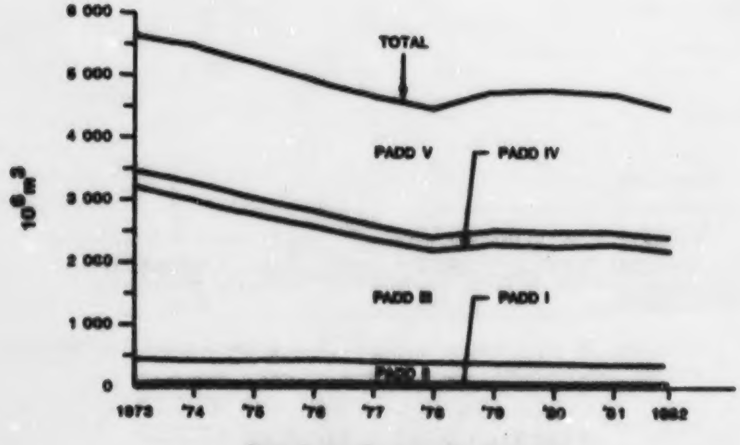
Field	API Gravity (°API)		Sulphur Weight (%)	1978 Producibility ($10^3 m^3/d$)
	Range	Average		
Alberta				
Bow River	15-32	27.0	2.2	7.9
Chauvin	14-26	24.0	2.6	0.6
Cold Lake	10-12	11.0	3.8-4.7	0.8
Lloydminster	10-17	15.0	2.9-3.5	6.0
Wainwright-Kinsella[a]	20-23	22.5	2.2-3.0	2.7
Saskatchewan				
Fosterton-Dollard	18-28	22.0	2.8	6.8
Midale	26-32	29.0	2.1-2.4	5.9
Smiley Coleville	13-17	-	1.7	2.1

SOURCE: J. M. Wilkinson, "Introduction to Heavy Oil Upgrading" in The Future of Heavy Crude and Tar Sands: First International Conference, edited by R. F. Meyer and C. T. Steele (New York: McGraw-Hill Inc., 1981), p. 591.

[a] Includes 40.0 percent Wainwright, 54.6 percent Kinsella, and 5.4 percent condensate.



Production

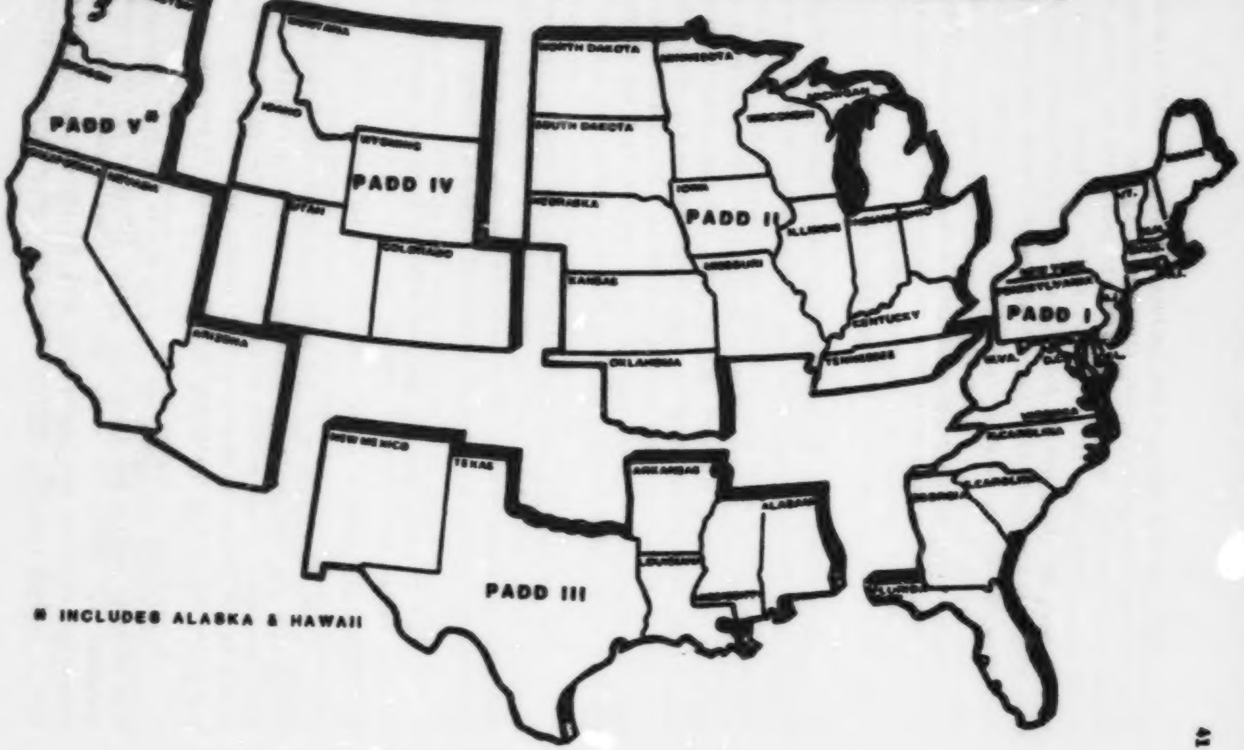


Remaining Recoverable Reserves

SOURCE: Table 3.3.

FIGURE 3.4: U.S. CRUDE OIL PRODUCTION AND REMAINING RECOVERABLE RESERVES: 1973-1982

FIGURE 3.6: PETROLEUM ADMINISTRATION FOR DEFENCE (PAD) DISTRICTS


PADD V*
OREGON
CALIFORNIA
NEVADA
ARIZONA
MONTANA
IDAHO
WYOMING
PADD IV
UTAH
COLORADO
NEW MEXICO
TEXAS
PADD III
NORTH DAKOTA
MINNESOTA
SOUTH DAKOTA
NEBRASKA
IOWA
PADD II
KANSAS
MISSOURI
OKLAHOMA
WISCONSIN
MICHIGAN
ILLINOIS
INDIANA
OHIO
KENTUCKY
TENNESSEE
ARKANSAS
LOUISIANA
ALABAMA
VT.
NEW YORK
PENNSYLVANIA
PADD I
W.VA.
DEL.
VIRGINIA
N.CAROLINA
S.CAROLINA
GEORGIA
FLORIDA

* INCLUDES ALASKA & HAWAII

While total production has fallen only about 6 percent since 1973, the proportion of production from two of the PAD districts has changed significantly. Specifically, PADD III production has fallen 34 percent since 1973 while PADD V production has increased 250 percent over the same period, primarily due to a sevenfold increase in Alaskan production. The production of the other three districts has remained relatively constant.

U.S. crude production data by quality of crude are available, but only on a well-by-well basis from the relevant state departments. Thus, it was not possible to identify trends in U.S. heavy crude production for either the total U.S. or individual states.

PAD District I is the smallest U.S. crude producer, accounting for only about one percent of total U.S. production since 1973.

PAD District II, the third largest U.S. producer, produced 59 million cubic metres of crude oil in 1982. Within the district, Oklahoma was the largest producer with 43 percent of the production representing 25 million cubic metres (see Table B.4). Historically, PADD II production has remained relatively constant in terms of both absolute volume and percentage of total U.S. production.

PAD District III has historically been the largest crude oil producing area and has remained the largest, despite declining production in recent years. Texas accounts for the vast majority of its total production, with some 61 percent of total 1982 output.

PADD IV production has declined almost 18 percent since 1973, and has fallen from about 7 percent to 6 percent of total U.S. production.

Crude oil production in PAD District V comes almost exclusively from Alaska and California, with the remaining states comprising less than one-quarter of one percent of the district's crude oil production. Alaska is the largest producer, with 61 percent of the district's 1982 production followed by California with the remaining 39 percent.

California and Alaska are the only states for which production data by crude quality are available. Table B.5 shows the API gravity breakdown for California crude oil. California has a very high proportion of heavy oil production, with 62 percent having an API gravity of less than 20°. Production of crude oil with an API gravity of less than 30° accounts for about 85 percent of total production. Less than one percent of California's production has an API gravity over 40°.

Alaskan crude oil production comes primarily from the Alaskan North Slope (ANS). Alaska North Slope crude has an API gravity of 26.4°.[2] ANS is blended with Kuparuk crude which has an API gravity of 23°. Alaska North Slope is produced at a rate of 254 000 cubic metres per day compared with Kuparuk crude with output of 19 000 metres per day.

3.2.4 U.S. Crude Oil Reserves

As of 1982 U.S. remaining recoverable reserves of crude oil were 4.4 billion cubic metres, down 21 percent from the 1973 level of 5.6 billion cubic metres (see Figure 3.4 and Table B.3). The U.S. 1982 total compares with 1.2 billion cubic metres remaining recoverable reserves in Canada in the same period. As with production, PADDs III and V accounted for over 80 percent of total reserves. However, while PADD V had a greater proportion of total reserves (46 percent compared with 41 percent in PADD III), it had a lower proportion of total production (32 percent as opposed to 48 percent). Moreover, PADD V's proportion of total reserves increased by about 9 percentage points since 1973, while PADD III's proportion of total reserves has fallen correspondingly.

Within the PADDs, certain states account for the bulk of total PADD reserves. Florida has over 50 percent of PADD I reserves, but is insignificant in terms of the U.S. total (see Table B.4).

PADD II has 338 million cubic metres of remaining recoverable reserves representing 8 percent of the total U.S. remaining recoverable reserves. Within the district, Oklahoma has 46 percent of the remaining reserves, followed by Kansas and North Dakota with 18 and 11 percent, respectively.

Texas has 1.2 billion cubic metres of remaining recoverable crude oil reserves, which accounts for 68 percent of PAD District III's recoverable reserves. The remaining 32 percent is largely accounted for by Louisiana, which has 24 percent of PAD III production.

Remaining recoverable crude oil reserves for PAD District IV total 225 million cubic metres, 61 percent of which are located in

Wyoming. The remaining 39 percent is distributed fairly evenly between Colorado, Montana and Utah.

Alaska and California have 99 percent of PADD V's crude oil reserves between them; 1178 million cubic metres and 859 million cubic metres of remaining recoverable reserves, respectively.

Detailed historical production and remaining reserves data for PADDs II to V are presented in Tables B.6 to B.10 of Appendix B.

As with production, U.S. crude reserves data are not readily available by quality of crude, except for California and Alaska. Because of this, it is impossible to discern trends in U.S. production and reserves in terms of heavy and light crude ratios. In general, it is evident that, as with Canada, total U.S. production and reserves are both on the decline. Nevertheless, such data limitations preclude accurate determination of United States heavy crude supply potential. This data would indicate the significance of alternative domestic supply sources that would compete with Canadian heavy crude exports in various regional United States markets.

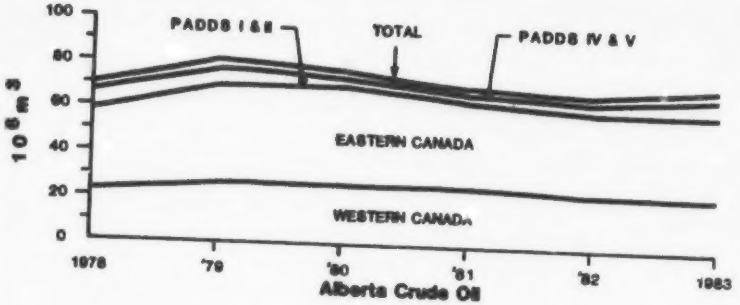
Having examined the supply side of the Canadian and U.S. crude oil market in terms of production and reserves (i.e., short- and medium- to long-term supply), the other side of the market, demand, will be examined. Specifically, short-term demand for Canadian crude will be indicated in terms of disposition in recent years. Analysis of the Canadian and U.S. refinery situations, with special emphasis on those refineries capable of handling heavy crude, will provide some indication of potential demand for Canadian heavy crude oil.

3.3 Canadian and U.S. Refinery Analysis

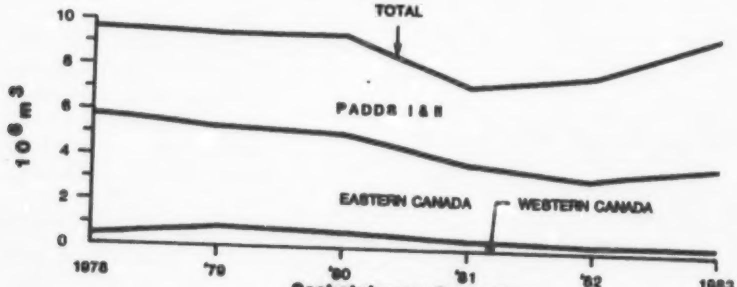
3.3.1 Disposition of Canadian Heavy Crude Oil

In 1983 some 80 percent of Canadian crude oil production was delivered to Canadian refineries, with the remainder exported to the U.S. (see Figure 3.6 and Table B.11). This percentage distribution has remained basically constant since 1978, although exports averaged about 12 percent of Canadian production from 1980 to 1982.

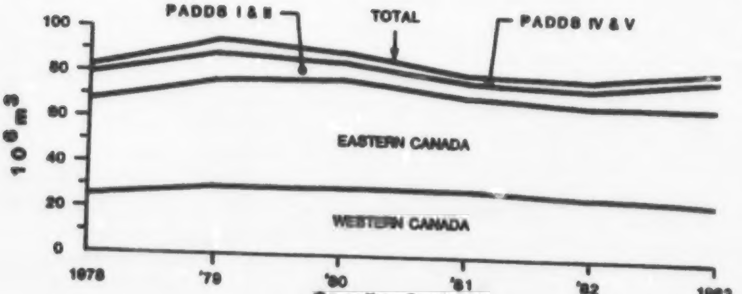
Alberta delivered 79 percent of its 1983 total crude oil production to the other provinces and the United States. Of the



Alberta Crude Oil



Saskatchewan Crude Oil



Canadian Crude Oil

SOURCE: Table B.11.

FIGURE 3.6: DISPOSITION OF CANADIAN CRUDE OIL: 1978–1983

Canadian provinces, Ontario is the largest recipient of Alberta crude, and has received about 35 percent of Alberta's yearly production since 1979. Alberta refineries have consumed about 20 percent of the province's own production historically.

Alberta crude is exported to four PAD districts in the United States, which accounted for 15 percent of Alberta's 1983 crude oil production or 19 percent of Alberta's out-of-province deliveries of crude oil.

Saskatchewan exports almost all of its crude oil production to other provinces and the United States. The United States receives the majority of the crude exports, with PADD II receiving 60 percent of Saskatchewan's 1983 production. This was the opposite of the situation in 1978 when Saskatchewan exported about 40 percent of its crude oil and the remaining 60 percent was delivered within Canada.

Ontario and Quebec are the major domestic recipients of Saskatchewan's crude oil production. Saskatchewan uses only about 2 percent of its own production.

3.3.2 Canadian Refineries

In 1977 the Canadian refining sector had a total crude processing capacity of 354 000 cubic metres per calendar day, 22 percent (78 000 cubic metres per day) of which was surplus to then-current levels of demand.[3] Utilization for 1976 had been higher at 85 percent, but surplus capacity was forecast to increase to over 100 000 cubic metres per day by 1980. Demand for refined petroleum products had increased 2.3 percent over 1975 and was forecast to increase only 2 percent in 1976,[4] which would further aggravate the excess capacity situation. Thus, no new major projects had been announced, or were anticipated for some time.

Despite the prevailing surplus capacity, new projects that had been planned years earlier and subsequently came on stream resulted in an anticipated net increase in capacity to 400 000 cubic metres per day by 1979.[5] Forecasts in 1978 for the following year indicated an increase in consumption of 4.7 percent over 1976. However, utilization was still anticipated to fall to 70 percent, and the expected surplus capacity exceeded levels previously forecast for 1980. Thus, refiners shifted their emphasis from major new construction to rationalizing "existing facilities to improve product yields and economies of operation [with] the only bright spot for major construction projects [lying] in any facilities which are built to upgrade heavy oils into pipelineable feedstocks."[6]

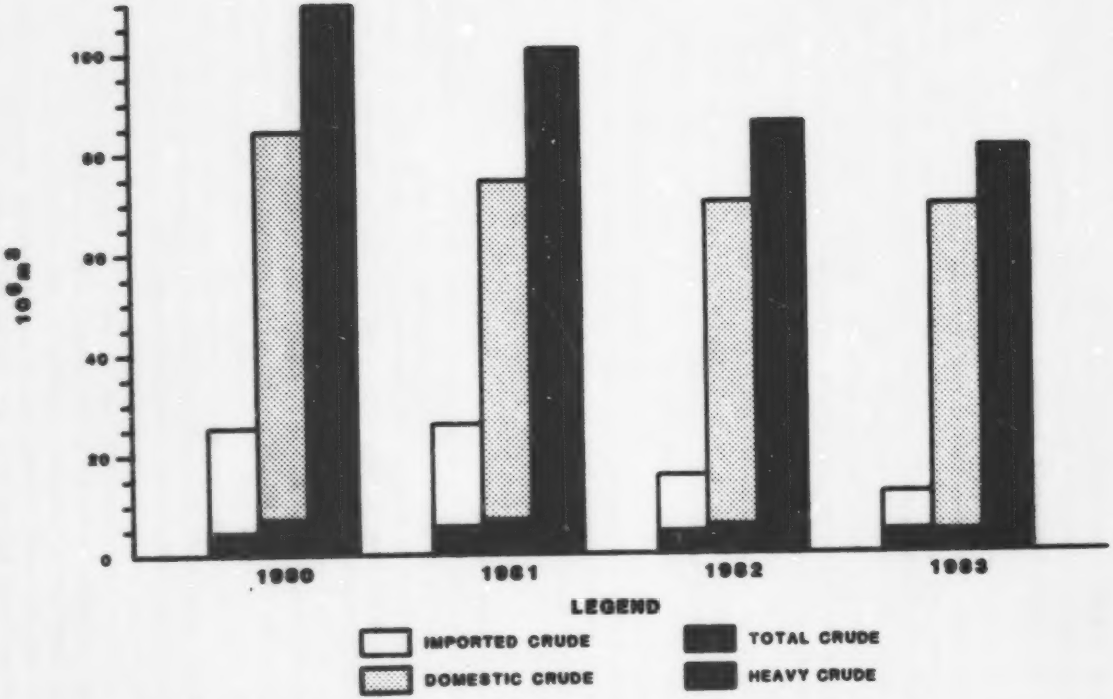
Product demand began to fall in 1980, and the demand mix moved toward light products, causing refiners to close some uneconomical operations and upgrade others to provide increased light product yields (see Table B.12).[7] In 1983 seven refineries comprising over 17 percent (51 400 cubic metres per day) of existing capacity were shut down, reflecting such factors as excess capacity, a 7 to 8 percent decrease in refined products demand in 1981 and 1982, respectively, and a forecast decline in refined products demand of almost 6 percent for 1983.[8]

This trend toward refinery closures is substantiated by the 18 percent decline in domestic crude oil receipts by Canadian refineries between 1980 and 1983 (see Figure 3.7 and Table B.13). However, domestic heavy crude oil receipts by Canadian refineries declined some 42 percent over the period, more than twice as much as light and medium crude oil receipts which fell only 16 percent. Overall, the proportion of domestic heavy to total receipts fell only 2.4 percentage points to 6 percent.

Volumes of Canadian imports of crude have also declined significantly, falling from 25 to 12 million cubic metres from 1980 to 1983 (see Figure 3.6 and Table B.13). However, the percentage of heavy crude as a proportion of total imports has increased from 18 to 36 percent over the same time period due to the decline in total imports, since heavy crude oil imports have remained relatively constant.

In total, Canadian refinery receipts of crude oil declined 26 percent from 1980 to 1983. The imports proportion of total light and medium crude receipts fell 10 percentage points over the period, from 21 to 11 percent, while the imports proportion of heavy crude receipts increased correspondingly. Nevertheless, the overall proportion of heavy to total crude receipts remained constant.

Eleven Canadian refineries currently nominate for significant volumes of heavy crude oil (see Figure 3.8).[9] The trend toward greater heavy crude refining capacity is evident in the increase in thermal operations, hydrotreating, and hydrocracking capacity at these refineries (see Figure 3.9 and Tables B.14 to B.25).[10] These processes have increased 14, 42, and 1,303 percent, respectively, since



SOURCE: Table 5.13.

FIGURE 3.7: TOTAL RECEIPTS OF DOMESTIC AND IMPORTED CRUDE BY CANADIAN REFINERIES: 1980-1983

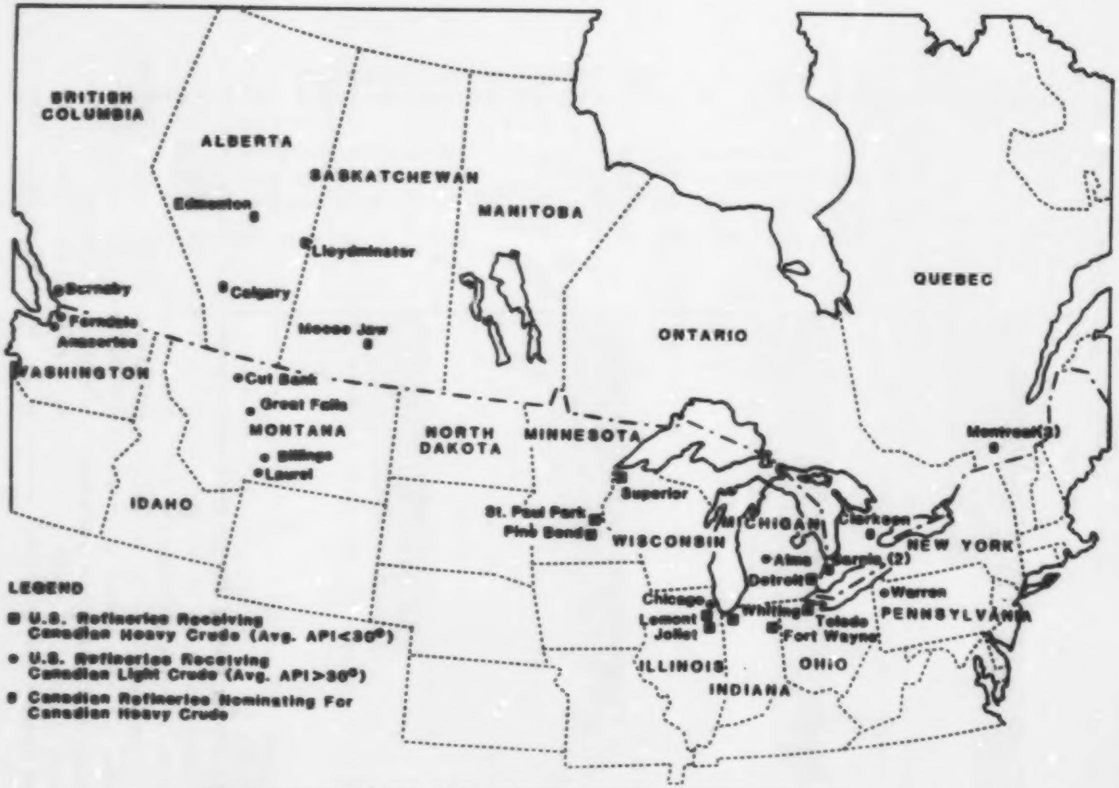
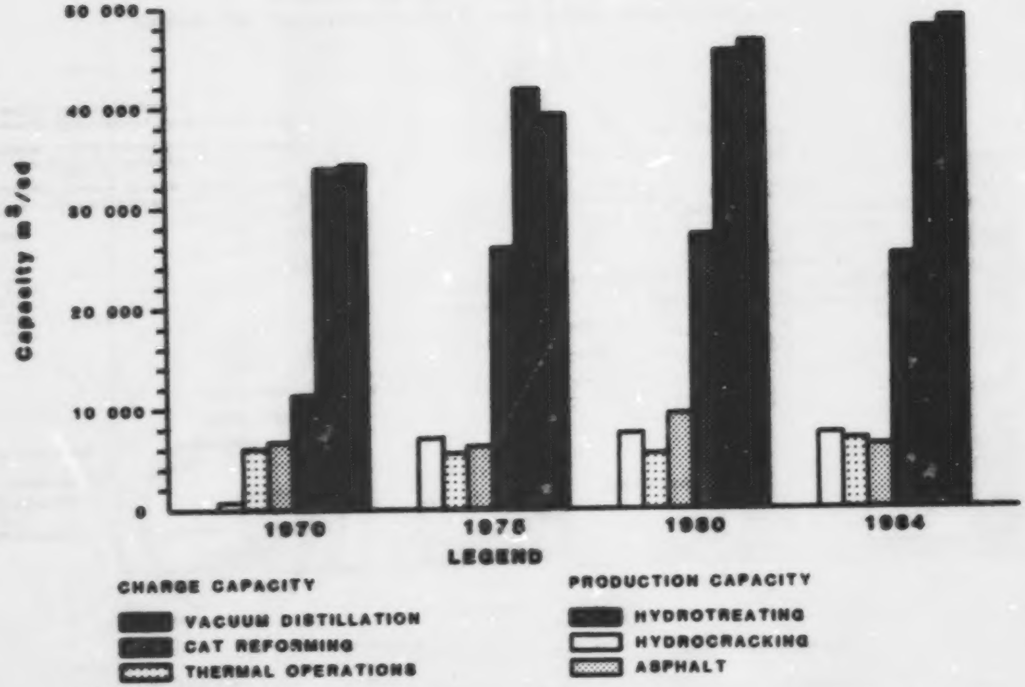

BRITISH COLUMBIA
ALBERTA
SASKATCHEWAN
MANITOBA
ONTARIO
QUEBEC
Edmonton
Lloydminster
Calgary
Moose Jaw
Burnaby
Ferndale
Anacortes
WASHINGTON
Cut Bank
Great Falls
MONTANA
Billings
Laurel
IDAHO
NORTH DAKOTA
MINNESOTA
Superior
St. Paul Park
Pine Bend
WISCONSIN
MICHIGAN
Alma
Detroit
Clarkson
Sarnia (2)
Montreal(3)
NEW YORK
Warren
PENNSYLVANIA
Chicago
Lemont
Joliet
Whiting
Toledo
Fort Wayne
ILLINOIS
INDIANA
OHIO
LEGEND
U.S. Refineries Receiving Canadian Heavy Crude (Avg. API<30°)
U.S. Refineries Receiving Canadian Light Crude (Avg. API>30°)
Canadian Refineries Nominating For Canadian Heavy Crude

FIGURE 3.8: CANADIAN AND U.S. REFINERIES NOMINATING FOR CANADIAN HEAVY CRUDE OIL IN 1983



SOURCE: Table B.14.

FIGURE 3.9: CONFIGURATION OF CANADIAN REFINERIES NOMINATING FOR CANADIAN HEAVY CRUDE OIL: 1970–1984

1970. Vacuum distillation capacity, also important for initial heavy crude oil processing increased over 40 percent over the same period. The twofold increase in catalytic reforming capacity likely facilitated the increase in hydrotreating and cracking as it releases hydrogen necessary for these operations. This trend toward increasing heavy crude refining capacity will likely continue with the increasingly heavy crude slate expected for the future.

The current situation facing Canadian refiners is somewhat improved as the decreases in refined product demand are not expected to continue, and will level out and possibly increase about 1.5 percent in 1984, if the economic upturn continues. Despite the closure of another two refineries "there still remains some culling of facilities to be undertaken in the coming months."[11] Continued strong light product demand will concentrate activities on new light end production processes, and greater efficiency of existing processes.

Despite a decrease in net refined product sales (net of products used captively by refiners) of 6.8 percent in 1983, domestic crude demand increased 6.9 percent for the first six months of 1984 over the previous year, and refiners' use of domestic feedstocks is anticipated to increase some 3.9 percent in 1984.[12] Product imports increased 19.0 percent in 1983, and foreign crude imports are projected to increase more than 11 percent in 1984.

The Canadian refining industry is currently facing several issues of prime importance to its present and future operations. The two basic concerns are heavier crude inputs and increased demand for light outputs. Investments in Canadian refining facilities in the past few years have concentrated on the processing of heavier crudes to accommodate these trends.

Despite the closure of several refineries and the improved processing efficiency of others, utilisation rates are still expected to fall slightly in the long term. Changes in both crude oil and product supply and demand mixes will continue to exert pressures on Canadian refiners. Realization of the forecast decreases in demand could possibly force marginal refineries to close operations. If legislation is introduced in Canada requiring higher gasoline octane levels, as has been done in other countries, further rationalization would be necessary at many refineries.[13] Thus, if product export markets do not improve, or if the economy (and therefore demand) does not expand, the long-term outlook for Canadian refining is not very optimistic.

3.3.3 U.S. Refineries

The U.S. has recently experienced major adjustments in its refining sector due to a variety of factors, both domestic and foreign. However, two general periods can be identified since 1973--pre-1979 and post 1979--for convenient summarization of the trends in the industry.

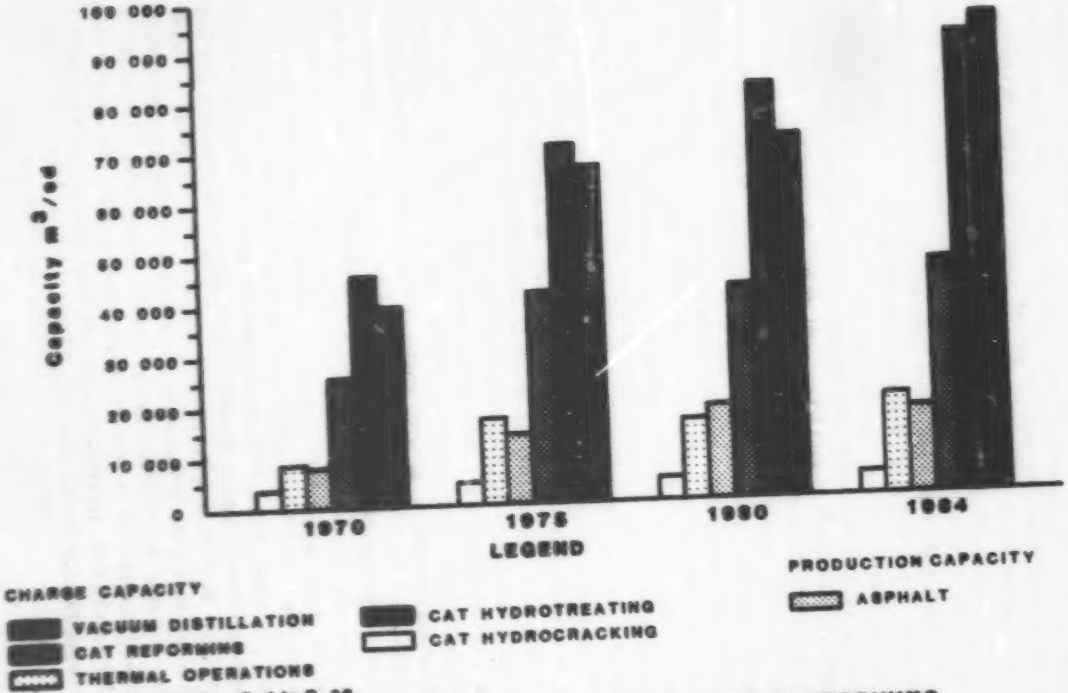
In 1973 the U.S. government introduced import fees on crude oil and refined petroleum products of 21 cents and 63 cents per barrel, respectively.[14] The differential encouraged crude refining in the U.S. as opposed to purchasing refined products. These fees and other legislation implemented regarding crude imports and pricing protected the domestic refining industry from foreign competition and decreased imports of refined products from 480 000 cubic metres per day in 1973 to 250 000 cubic metres per day in 1980.[15] Although capacity utilization was high for domestic refiners for most of this period while foreign refiners experienced excess capacity, the temporary nature of the protectionist measures, plus the price controls imposed on large refiners, kept large refiners from making long-term investments in either upgrading existing facilities or building new facilities. On the other hand, additional subsidies available to smaller refineries encouraged this sector such that 56 new refineries, generally with capacities of less than 1600 cubic metres per day were constructed at a rate of almost one per month from 1974 to 1979.[16] The net effect was a relative increase in light product production capacity due to the relatively simple configurations of these refineries.

Since import fees were suspended in 1979 and all price and allocation controls were eliminated in 1981, the shape of the U.S. refining industry has changed considerably. In 1980 the 303 operating oil refineries in the U.S. had a capacity of some 3 million cubic metres per day and an average utilization rate of 70 percent. Crude input to refineries was 2.1 million cubic metres per day. As of January 1, 1984 these figures had decreased to 247 operable refineries with a capacity of 2.6 million cubic metres per day and a 1983 crude input of 1.9 million cubic metres per day. However, the average 1983 utilization rate increased slightly to 72 percent.[17]

These figures indicate greater efficiency in existing facilities and closure of relatively inefficient operations as the number of refineries fell 18 percent,[18] but capacity and crude input decreased only 13 percent and less than 10 percent, respectively. Moreover, the low utilization rates of 1981 and 1982 rose through 1983, peaking at 78 percent in September of that year.

"Decontrol has...radically altered the economic environment in which the U.S. refining industry must compete."[19] In addition, shifts in demand toward lighter products, and in refinery capacity toward greater processing flexibility are continuing the trend of eliminating inefficient facilities and consolidating and streamlining existing operations.[20] Refiners are taking advantage of the current lull in demand to upgrade their facilities to accommodate heavy crude oil inputs. Capacity for catalytic cracking and hydrocracking, two heavy oil processing operations, is expected to increase by about 11 000 cubic metres per stream day and 8000 cubic metres per stream day, respectively, in 1984; an increase of more than 1 and 5 percent, respectively.[21]

This trend is evident in Figure 3.10 which shows historical refinery configuration data for the nine U.S. refineries that are the major recipients of Canadian heavy crude oil. (See Figure 3.8 for the location of these refineries. Note that the U.S. refineries receiving Canadian heavy crude oil also receive some light crude and/or condensate in the blend. Tables B.26 to B.35 detail historical configuration for these refineries.) As with Canadian refineries, U.S. refineries have increased their heavy crude operations capacity significantly since 1970. Thermal operations and hydrotreating capacity more than doubled over the period as compared with a 14 percent and a 40 percent increase in these capacities in Canadian refineries over the same time period. On the other hand, U.S. hydrocracking capacity increased only 8 percent as opposed to a thirteenfold increase in Canadian hydrocracking operations. Vacuum distillation capacity and asphalt production capacity also doubled over the period. The increase in coke production of more than 190 percent, combined with the aforementioned increases in other heavy crude oil processing capacities, indicates a significant increase in potential demand for heavy crude oil. As previously noted, U.S. heavy crude oil refining capacity is expected to increase even further in the near future.



SOURCE: Table 3.26.

FIGURE 3.10: CONFIGURATION OF U.S. REFINERIES RECEIVING CANADIAN HEAVY CRUDE OIL: 1970-1984

This projected increase in capacity seems contradictory in light of the current low levels of demand for petroleum products, the numbers of refineries that have been closed, and the amount of idle capacity in the industry. This issue is resolved in that:

> ...much of this [available] capacity cannot process heavy and sour crude oil into light petroleum products (such as gasoline) even though these crudes are becoming an increasing fraction of world supply. Thus, new investment is desirable despite an apparent excess capacity in the refining industry.[22]

These trends are expected to continue in the short term. Crude distillation capacity is projected to increase to 2.7 million cubic metres per stream day by the beginning of 1985,[23] despite recent decreases in domestic demand for petroleum products. Crude oil inputs are expected to increase more than 10 percent by 1985 over 1983 levels,[24] and the recent reduction in the use of foreign crude is likely to continue in the short term. The output mix is projected to become slightly heavier, with production of wax, asphalt, and road and lubricating oils increasing some 11.5 percent by 1985 over 1983, compared with a 9.1 percent increase in motor gasoline production over the same period.[25] However, the relatively low increase in gasoline production is due to a 2.1 percent decrease in leaded gasoline combined with an 18.2 percent increase in unleaded gasoline as more vehicles and new legislation require the use of unleaded fuel.[26]

Thus, the U.S. refining industry has moved from an era of relatively simple, smaller refineries protected and assisted by legislation to an age of decontrol and declining demand in which greater refinery complexity, efficiency, and capacity are stressed to accommodate heavier crude inputs.

3.4 Demand Potential for Canadian Heavy Crude Oil

The previous analysis has shown that, while Canadian crude oil production is falling, heavy crude production is increasing. Moreover, demand for heavy crude, in terms of increased heavy crude refining capacity in both Canada and the U.S., is also increasing and is expected to continue to do so in the short term, indicating a relatively stable market for Canadian heavy crude oil production. This is particularly true for the Eastern Canadian and Northeastern U.S. refineries mentioned earlier as being recipients of Canadian heavy crude oil. On the other hand, major U.S. producers such as PADDs II and III, and U.S. heavy crude producers such as PADD V could potentially capture some of the existing and expected market. Analysis of historical nominations and receipts of heavy crude oil by Canadian and U.S. refineries will provide some indication of the demand potential for Canadian heavy crude oil.

3.4.1 Canadian Heavy Crude Oil Refining Capacity

As previously mentioned, nine refineries are the major Canadian recipients of Canadian heavy crude oil production. In 1983 these refineries nominated for 7400 cubic metres per calendar day of heavy crude on the average, amounting to some 2.7 million cubic metres of heavy crude oil (see Table B.36). This total represented only about 6 percent of total capacity for these refineries.

The difficulty in coming to a firm conclusion regarding total heavy crude capacity lies in the fact that heavy crude capacity per se cannot be identified for a given refinery, and that receipts data by quality of crude are available by province, but not by refinery. Since refineries are normally free to sell or exchange any crude received, and since nominations are in no way indicative of actual receipts, the actual amount of heavy crude received by any particular refinery cannot be determined by publicly available data. Therefore, the incremental amount of heavy crude which could be accepted by any refinery (i.e., the potential demand) may not be identified.

Some degree of seasonality of demand may, however, be identified by examining monthly heavy crude nominations by Canadian refineries (see Table B.37). Increased asphalt demand during the summer months is the primary reason for the increase in heavy crude nominations for these months. This seasonality generally holds for nominations for production from individual provinces as well, with the overall low occurring in April. This fact is significant insofar as it identifies periods when additional Canadian heavy crude may be available for export, particularly for export to areas where heating demands increase heavy crude requirements during the winter months.

3.4.2 U.S. Heavy Crude Oil Refining Capacity

Nominations, authorized exports, and actual deliveries data for the nine major U.S. refinery recipients of Canadian heavy crude oil indicate possible excess heavy crude capacity in addition to that of Canadian refineries (see Tables 3.2 and B.38). Total Canadian and total foreign heavy crude receipts amounted to only 17 percent and 3 percent, respectively, of total 1983 refinery capacity, allowing for possible displacement of other imported heavy crudes, if not for additional heavy crude capacity. Moreover, the fact that nominations, authorized exports, and actual deliveries for Canadian heavy crude oil have all doubled since 1981 also indicates an increasing capability to handle heavy crude.

Appendix Table B.39 presents similar data from 1980 to 1984 for seven of these nine U.S. refineries.

Three refineries in the United States represent almost 80 percent of all heavy crude oil deliveries from Canada. These are the Koch refinery in Pine Bend, Minnesota, the Mobil refinery in Joliet, Illinois, and the Amoco refinery in Whiting, Indiana. Detailed analysis of historical nominations, authorized exports, and actual deliveries for these refineries will further illustrate the potential for increased demand for Canadian crude production, as well as clarify the limitations of such analysis due to data problems.

The Koch refinery in Pine Bend, Minnesota is by far the largest U.S. recipient of Canadian heavy crude oil. The Koch refinery has been steadily increasing its receipts of Canadian heavy crude since 1980 such that by 1983 Koch was using Canadian heavy crude almost exclusively (see Figure 3.11). Thus, the potential for increased Canadian heavy crude exports to Koch would depend on capacity additions. On the other hand, potential disruptions in Koch's Canadian requirements would be significant as its 1983 heavy crude receipts accounted for over 40 percent of total Canadian crude exports to the U.S., and 60 percent of total U.S. imports of Canadian heavy crude.

Mobil refinery at Joliet, Illinois received the second highest volume of 1983 Canadian heavy crude exports (11 percent), but accounted for only 8 percent of total Canadian crude oil exports to the United States. As will be discussed in a later section, refineries like Mobil at Joliet offer potential for increased Canadian heavy crude receipts

TABLE 3.2

CANADIAN HEAVY CRUDE OIL RECEIPTS BY MAJOR U.S. REFINERIES[a] 1980-1983

Refiner/Location	Canadian Heavy Crude Deliveries (10^3m^3)				% of 1983 Canadian Deliveries	Avg. API° of 1983 Canadian Deliveries	1983 Foreign Heavy Crude Deliveries (10^3m^3)	1983 Refinery Capacity[b] (10^3m^3)
	1980	1981	1982	1983				
Koch/Pine Bend, Minn.	3 590	4 736	6 927	7 246	60.0	NR	-	7 718
Mobil/Joliet, Ill.	1 135	550	1 085	1 367	11.3	22.9	1 361	10 446
Amoco/Whiting, Ind.	-	-	171	813	6.7	25.5	400	21 819
Marathon/Detroit, Mich.	5	-	29	765	6.3	26.4	86	3 975
Union/Lemont, Ill.	25	42	67	492	4.1	24.0	55	8 763
Sun/Toledo, Ohio	-	32	-	16	0.1	28.7	-	6 847
Murphy/Superior, Wis.	296	273	291	255	2.1	23.6	-	2 321
Gladieux/Fort Wayne, Ind.	-	-	91	81	0.7	26.7	-	1 079
Ashland/St. Paul Park, Minn.	428	125	152	103	0.9	24.3	-	4 004
Total[c]	5 478	5 759	8 812	11 138	92.3	24.4[d]	1 902	66 973
Total U.S.	6 023	5 806	9 034	12 085	100.0	NR	64 654	NA

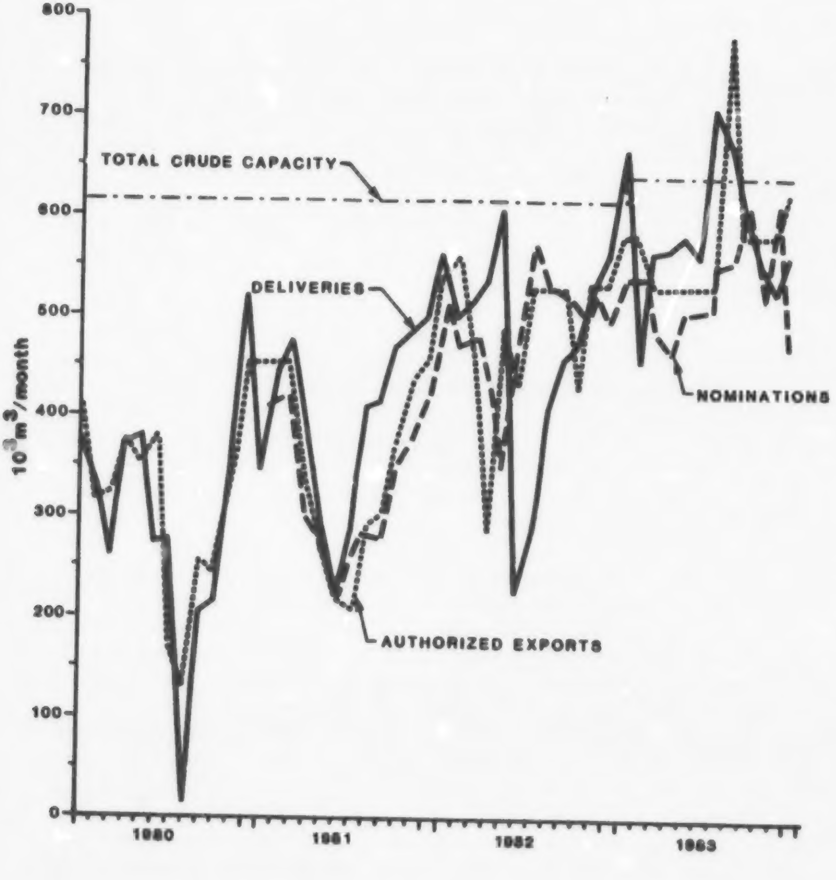
SOURCES: (1) American Petroleum Institute, Imported Crude Oil and Petroleum Products Reports (Database); and (2) Tables B.27 to B.35, and B.39.

[a] Includes heavy crude less than or equal to 29° API. Figures may not add due to rounding.

[b] Based on refinery capacity per calendar day, except Ashland, based on capacity per stream day.

[c] Totals may not add due to rounding.

[d] Total weighted average, excluding Koch.



SOURCES: Tables B.41 to B.43.

FIGURE 3.11: KOCH REFINERY AUTHORIZED EXPORTS, DELIVERIES, AND NOMINATIONS OF CANADIAN CRUDE OIL, 1980-1983

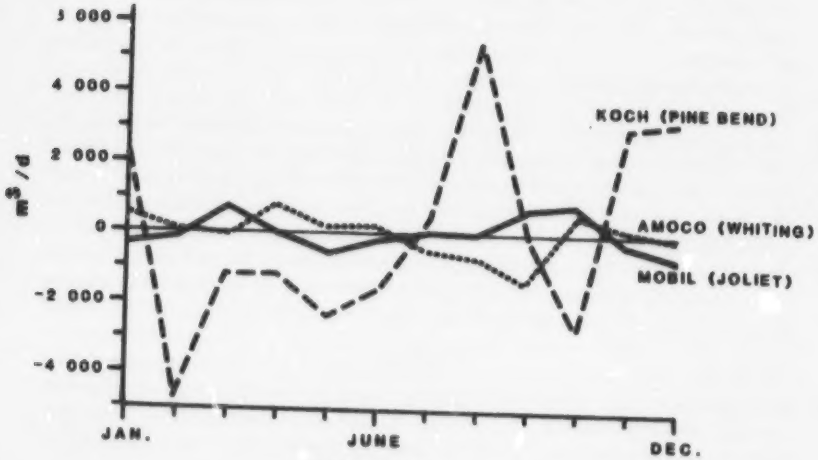
by displacing imports of other foreign heavy crudes. Mobil is a particularly good prospect because it imports as much foreign as Canadian heavy crude oil.

The Amoco refinery in Whiting, Indiana is the third largest recipient of Canadian heavy crude, representing about 7 percent of total Canadian heavy crude receipts in 1983. The Amoco refinery is almost three times the size of the Koch refinery, and also imports a significant amount of foreign heavy crude oil.

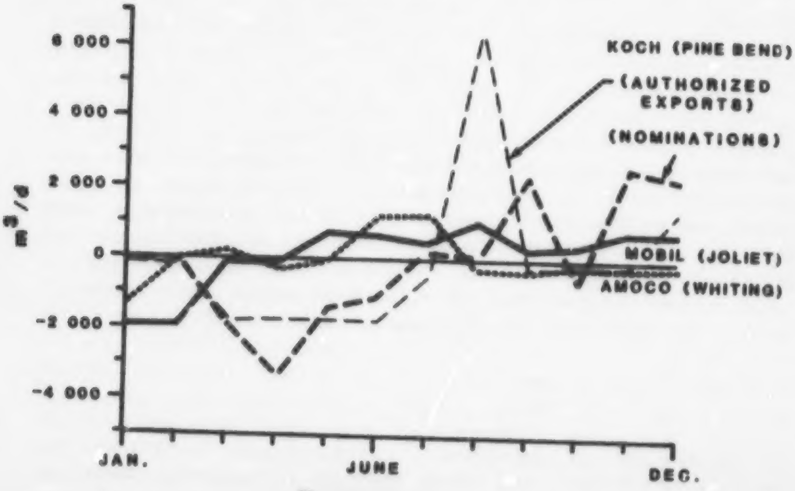
Monthly data for 1983 for the Koch refinery indicate some seasonality in terms of heavy crude nominations by Koch, generally peaking in the fall (see Tables B.40 to B.43). This trend is evidenced in Figure 3.12, which depicts the variations about the mean of Canadian crude oil deliveries, authorized exports, and nominations to the three major U.S. refineries being analyzed. Both deliveries and authorized exports for Koch peak in August and again in December.

Overall, the data for the Koch refinery seem to indicate some seasonality of demand for Canadian heavy crude peaking in the fall months. However, similar data for the Mobil refinery in Joliet, Illinois and the Amoco refinery in Whiting, Indiana do not corroborate this finding (see Figure 3.12 and Tables B.44 and B.45). Total Canadian heavy crude nominations by the Mobil refinery peak in November and December. Authorized exports remain virtually unchanged over the year, while actual deliveries peak slightly in March and in the fall. Nominations for the Amoco refinery peak in June and July, but remain relatively constant for the rest of the year. Deliveries peak slightly in April. Thus, no clear conclusion may be drawn from these data as the "demand" levels indicated peak in the fall, winter and summer for Koch, Mobil and Amoco, respectively.

The problem with drawing any conclusion is that the direction of impact of the various factors is not clear. For example, earlier analysis concluded that Canadian refiners' demand for heavy crude peaks in the summer months. Because of this seasonality, less Canadian production is available for export, since the NEB will only authorize exports from production surplus to Canadian requirements. Thus, Koch refinery's nominations may be lower in the summer since it does not expect to receive a great deal of Canadian production at that time. On the other hand, this fact may also explain why Amoco's nominations are high at this time, so as to obtain as much as possible. Thus, nominations may not be indicative of demand for heavy crude as Koch may



Deliveries



Nominations

SOURCES: Tables B.40, B.44, and B.45.

FIGURE 3.12: CANADIAN CRUDE OIL DELIVERIES, AUTHORIZED EXPORTS, AND NOMINATIONS TO MAJOR U.S. REFINERIES, 1983 (VARIATIONS ABOUT THE MEAN)

nominate for volumes much lower than their actual demand based on their expectations regarding actual receipts. Amoco's nominations may be much higher than their demand in order to secure adequate feedstock during a period of reduced export volumes.

In addition to the above, actual demand is further obscured in that deliveries and authorized exports are not indicative of demand either. Excess crude deliveries may be sold to another refinery, and shortages may be made up by purchases that are not indicated by the available data. Moreover, it is not clear whether actual deliveries are a simple function of authorized exports based on existing surplus production, or whether deliveries are determined by authorized exports as determined by the level of nominations. In addition, no clear, direct relationship exists between nominations, authorized exports, and actual deliveries. This is highlighted by Figure 3.11 which shows that deliveries to the Koch refinery actually exceeded their authorized exports and nominations on several occasions between 1980 and 1983. This anomaly emphasizes the difficulty in determining a given level of demand for U.S. refiners.

Finally, demand analysis and precise determination of demand potential are precluded by the complexity of factors which determine the crude mix received by refineries. Specifically, many possible reasons exist for taking relatively more or less of a given crude quality, reasons not always indicative of demand. For example, the Koch refinery accepted some (partially processed) synthetic crude when the Syncrude plant shut down. Similarly, the varying amounts of light, medium, and heavy crude oils accepted may be more a function of their relative or combined API gravities than of specific demand for individual crudes (e.g., a heavy crude with a very low API gravity can be mixed with a great deal of relatively low API light crude as diluent, or very little relatively high API light crude).

3.4.3 Displacing Alternative Supply Sources

Regardless of these qualifications and data limitations, the available data indicate some excess heavy crude processing capacity in the Canadian and U.S. refineries outlined. Monthly data indicate potential peaking of demand in the summer and fall months at these refineries. In addition to this possible source of incremental demand for Canadian heavy crude production, the possibility of displacing alternate sources of heavy crude supply must also be examined.

Both Canada and the U.S. import some heavy crude each year. As previously discussed, Canadian imports of crude oil have been decreasing, but the percentage of heavy crude imports has been increasing. As all crude imports are absorbed by Eastern Canada, offsetting this production with Canadian heavy crude would depend on the relative cost, including transportation, from Western Canadian oil fields. Again, available data do not distinguish the particular refineries where this could occur.

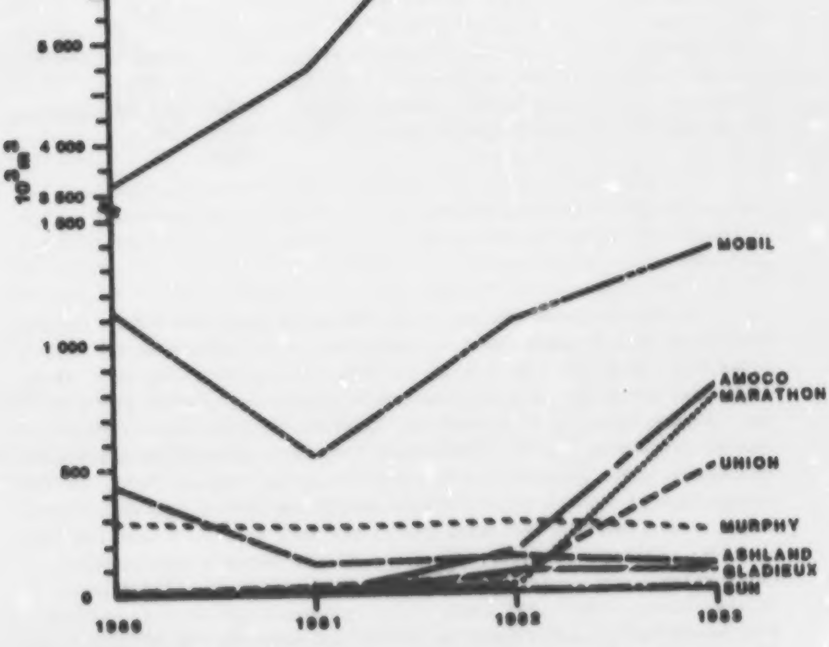
The U.S. situation for the selected group of refineries in terms of historical Canadian heavy crude deliveries is presented in Figure 3.13 and Table 3.2. Total imports of Canadian heavy crude by these refineries more than doubled from 1980 to 1983. However, as of 1983, other foreign heavy crudes accounted for almost 15 percent of total foreign heavy crude deliveries, indicating a potential market for Canadian heavy crude by displacing these other streams. Again, this depends on total costs after transportation, and on the capability of the refinery to accept Canadian heavy crude.

Figure 3.8 indicates various other U.S. refineries that accepted lighter Canadian crudes in 1983. These also represent market potential if lighter crude streams can be displaced by Canadian heavy crude oil.

A further possibility is for Canadian heavy crude to displace U.S. heavy crude streams to U.S. refineries. As previously mentioned, major U.S. crude producers such as PADDs II and III, and U.S. heavy crude producers such as PADD V currently supply significant portions of U.S. demand, and could potentially displace current and/or projected imports of Canadian heavy crude given favourable production and market situations. The extent of this competition on the one hand, or the possibility of Canadian heavy crude displacing U.S. production on the other is difficult to determine due to the lack of U.S. production data by crude quality. However, in general, the heavy metals content of Californian heavy crude, and the greater transportation requirement of Alaskan heavy crude could limit their potential use by U.S. refiners, and hence their competition to increased Canadian heavy crude oil exports to the United States.

3.5 Summary and Conclusions

Analysis of historical heavy crude oil supply data in terms of production and reserves, and demand data in terms of disposition and



SOURCE: Table 3.2.

FIGURE 3.13: U.S. REFINERY ANNUAL RECEIPTS OF CANADIAN HEAVY CRUDE OIL: 1980-1983

refinery configuration, has revealed several trends regarding the market for Canadian heavy crude oil. Production on the whole is falling, but both the absolute amount and the relative proportions of heavy crude oil are increasing in Canada. Due to the lack of regionally and nationally disaggregated domestic production data by crude type, it is not possible to identify United States trends. Nevertheless, production from PADDs II, III, and V could provide strong competition for Canadian crude in U.S. markets. On the other hand, historical data indicate that Canadian production has already made considerable inroads into U.S. markets, and indications are that this trend will continue.

On the demand side, increasing heavy crude processing capacity in the eleven Canadian and nine U.S. refineries that are major recipients of Canadian heavy crude oil, and increasing nominations and deliveries further indicate strong demand for Canadian heavy oil. However, data limitations regarding the amounts of crude actually received and processed by each refinery, and their absolute potential for heavy crude runs precludes an accurate estimation of potential demand for Canadian heavy crude oil. The forces behind nominations, authorized exports, and actual deliveries are numerous and unclear as to both their intensity and direction. Finally, given that production does not necessarily equal available supply, and that nominations do not equal demand due to uncertainties and expectations, no certain forecast of the Canadian heavy crude market situation may be given.

Certain additional data are required to specify the extent of the U.S. market potential for Canadian heavy crude oil exports. First, a thorough analysis of Canadian and U.S. refinery configuration and existing pipeline networks is necessary to determine the volume potential and geographic location of the currently accessible (short-term) market. Long-term demand potential could be determined given data on refinery and pipeline expansion plans, and feasibility analysis of incremental refinery capacity and pipeline facilities. Moreover, detailed information is necessary on receipts of crude oil by type for individual refiners, and on the resultant product slate. Currently available data fail to give the full extent of this demand side analysis because the particular crude streams and volumes to Canadian refineries, the particular crude streams to U.S. refineries, and the transfers and exchanges between both Canada and U.S. refineries cannot be identified.

Finally, the volumes and characteristics of U.S heavy crude oil received by U.S. refineries, and the heavy crude production potential and reserves of the U.S. PAD districts must be specified to determine the volume of domestic crude that could be displaced by Canadian heavy crude oil exports.

Accurate supply estimation would require disaggregated U.S. production and reserves data by types of crude to identify competing sources of supply. Further analysis is also required regarding the delivered cost of both Canadian and U.S. heavy crudes to identify those Canadian resources which could be recovered economically.

Despite these limitations, the historical analysis has identified some market potential for Canadian heavy crude oil exports to Northeastern U.S. refineries insofar as current imports of foreign heavy crude oil may be displaced, and the aggregate amount of heavy crude received is small relative to total capacity. Given this demand potential, some analysis of the Canadian heavy crude oil market situation is required to determine the exportable surplus of Canadian heavy crude oil. Although the uncertainties and unknowns mentioned above obscure the actual and expected state of this market, some general statements may be made by analyzing available data and by giving due consideration to the expectations of key industry and government players. The following chapter will develop a synthesized forecast for supply and demand for Canadian heavy crude oil based on such data.

Footnotes

[1] Reserves indicate only one part of long-term supply, which also includes new discoveries and improvements in recovery efficiencies. However, reserves levels define medium-term supply limitations, and provide some indication of ultimate long-term supply levels.

[2] Leo R. Aalund, "Assay Series Concludes with Index, U.S. Streams," Oil and Gas Journal, December 19, 1983, p. 71.

[3] Oilweek, June 6, 1977, p. 12.

[4] Ibid., p. 30.

[5] Oilweek, October 9, 1978, p. 30.

[6] Ibid., p. 30.

[7] Canadian domestic demand for light products as a proportion of total demand increased 5.6 percentage points from 1974 to 1983. This amounts to 4.4 million cubic metres based on total 1983 domestic demand of 78.5 million cubic metres. The percentage of light products to total supply increased only 4.8 percentage points over the same period. See Table B.12.

[8] Oilweek, May 30, 1983, pp. 20 and 30.

[9] Nominations for heavy crude oil are handled by the Alberta Energy Resources Conservation Board (ERCB) and the Alberta Petroleum Marketing Commission (APMC). A refiner nominates for given volumes and types of crude to the ERCB. The total nominations for a given month are compared with the productive capacity for that month. If nominations are less than productive capacity, the required production is prorated to various wells within the bounds of any maximum, minimum, or basic well rate that may apply. This seldom occurs, because nominations generally exceed productive capacity. In this latter instance, the APMC allocates supply to those who nominate based on a percentage of a refiner's historical take. For example, if productive capacity is 90 percent of nominations, a given refiner will receive 90 percent of his historical nominations rather than 90 percent of his nominations for that month. This procedure is the same for nominations by both domestic and U.S. refiners, except American refiners must also receive permission for a given level of authorized exports from the National Energy Board (NEB). A U.S. refiner contacts a Canadian crude oil producer with a request for a given amount of crude, and the Canadian producer in turn applies for an export license.

Two basic conditions must be met before a license is granted: the crude must be surplus to anticipated Canadian requirements over the following months; and the crude price must be "just and reasonable," in compliance with the price set by Cabinet on advice from the NEB. The maximum period covered by a license is one year. All crude surplus to domestic requirements is authorized for export, but not all licensed volumes are actually exported. For more information, see the National Energy Board Act, Part VI, sections 81 to 83.

An Energy, Mines and Resources Canada Communique released December 17, 1984 outlined changes in NEB policy regarding nominations for Canadian light crude oil that could have implications for domestic heavy crude oil. According to the communique, high nominations by Eastern Canadian refiners have "resulted in unstable total domestic demand for Canadian crude oil and the risk of oil being shut in, or not produced." In the future, historical performance and Canadian market trends will be closely analyzed in the NEB's determination of exportable surplus, and domestic refiners' nominations will be discounted when they appear to be excessive. Moreover, export licenses for light crude may be issued for a period of up to six months rather than the typical one month period, but only when surpluses are evident and other conditions permit. The export of Canadian heavy crude could be facilitated if such conditions were extended to include heavy crude oil as well.

[10] An important distinction exists between charge and production capacity in the process capacity data presented. Charge capacity refers to crude oil measured as input volumes. Production capacity refers to crude oil measured as output volumes.

[11] Oilweek, April 16, 1984, p. 11.

[12] Ibid., pp. 16-24.

[13] In late 1983 the Minister of Environment proposed decreasing the lead content in gasoline to 0.29 grams per litre by January 1, 1987. The proposal was published, but its future is uncertain given the change of government. Regardless, it would likely be some months before the legislation would be passed and enacted. See Leo R. Aalund, "Canadian Refining Industry Now Faces Several Challenges," in Oil and Gas Journal, March 26, 1984, p. 77.

[14] United States Senate Committee on Finance, Subcommittee on Energy and Agricultural Taxation, Incentives for Domestic Refining, Hearing before the Subcommittee on Energy and Agricultural Taxation of The Committee on Finance United States Senate (Washington, D.C.: U.S. Government Printing Office, 1981), p. 10.

[15] Ibid., p. 12.

[16] Ibid., p. 7. All of these refineries have capacity of less than 6400 cubic metres per day, and over 60 percent of them have capacity of 1600 cubic metres per day or less.

[17] National Petroleum Refiners Association, U.S. Refining Capacity: 1984 (Washington, D.C.: National Petroleum Refiners Association, 1984), p. iii.

[18] Eighteen refineries were closed in 1983, the majority of which had capacity less than 4800 cubic metres per day, which resulted in the lowest number of refineries reported since 1918.

[19] U.S. Senate Committee, Incentives for Domestic Refining, p. 22.

[20] U.S. domestic light products demand as a proportion of total domestic demand increased 3.9 percentage points from 1973 to 1982. This percentage amounts to some 32.4 million cubic metres of the total 1982 domestic demand of 831.2 million cubic metres. The proportion of light to total U.S. product supply increased only half a percentage point over the same period. See Table B.12.

[21] National Petroleum Refiners Association, U.S. Refining Capacity: 1984, p. v. Percentages based on total U.S. catalytic cracking and hydrocracking capacity of 952 250 cubic metres per stream day and 149 270 cubic metres per stream day, respectively. See "Annual Refining Report," Oil and Gas Journal, March 21, 1983.

[22] U.S. Senate Committee, Incentives for Domestic Refining, p. 6.

[23] National Petroleum Refiners Association, U.S. Refining Capacity: 1984, p. iii.

[24] Ibid., p. 26.

[25] The end result behind the heavy crude processes described above is to increase the light product yield from heavy crude inputs. For example, thermal operations break down and rearrange hydrocarbon molecules to increase the yield of blending components for motor gasoline. Hydrocracking also increases the yield of these components, and hydrotreating upgrades the quality of petroleum product outputs. Thus, a heavier crude input slate is not incompatible with a light crude output slate.

[26] National Petroleum Refiners Association, U.S. Refining Capacity: 1984, p. 26.

Chapter 4

CANADIAN HEAVY CRUDE OIL SUPPLY/DEMAND: OVERVIEW AND SYNTHESIS OF INDUSTRY AND GOVERNMENT FORECASTS

4.1 Introduction

This chapter presents an overview and synthesis of forecasts for the Canadian supply of heavy crude oil and the Canadian demand for Canadian heavy crude oil over the period 1984 to 2000. The majority of the material has been extracted from various corporate submissions and the Saskatchewan government's submission to the National Energy Board (NEB) in response to its request for input into the "NEB Update of Energy Supply and Demand, 1983 to 2005." The NEB results provided in their publication, Canadian Energy Supply and Demand 1983-2005, are also utilized. In addition, material was extracted from: (1) the Alberta Energy Resources Conservation Board's report, Alberta Oil Supply 1983-2007; (2) the Canadian Petroleum Association's report, The Economic Impact of Changes in Energy Prices and Taxation Proposed by the Canadian Petroleum Association, prepared by Chase Econometrics Canada; and (3) Energy Market Analysis and Statistics Division of Energy, Mines and Resources Canada's Energy Strategy Branch report, Long-Term Energy Supply/Demand Outlook: Spring 1984 Forecast.

Heavy crude oil supply and demand projections are discussed in that order, highlighting the high, low, and average forecast values. A synthesized supply and demand forecast is then derived based on those values to indicate possible exportable surplus volumes of Canadian heavy crude oil.

4.2 Industry Forecasts of Canadian Heavy Crude Oil Supply

While the NEB submissions are the most comprehensive data on future supply trends for Canadian heavy crude oil, the considerable divergence in underlying assumptions and scenarios employed by the various submitters limits the value of the data to some extent. For example, the NEB requested that submissions include both conventional heavy crude oil (i.e., crudes with an API gravity less than 29°) and non-conventional heavy crude (i.e., bitumen derived from in-situ oil sands operations, and synthetic crude from oil sands mining operations). Conventional heavy crude production forecasts were to take into consideration reserves additions from appreciations, new discoveries, and EOR techniques, as well as productivity from established reserves. However, some submissions only considered conventional heavy crude oil, while others only included heavy crude production from established reserves.

The views of the submitters on the definition of heavy oil are not so widely divergent as they are unclear, with only four specifically defining what they meant by heavy oil. The remainder offered no clear definitions and left the reader to infer from various tables and graphs what was included.

This vague approach to definition produces three major problems. First, it is unclear whether or not the submissions follow the NEB definition by including the Weyburn-Midale crude stream (a relatively "light" heavy crude) in the definition of heavy oil and, subsequently, in their forecasts. Second, the methodology used by each submission to measure the heavy oil and bitumen used to produce synthetic oil is uncertain. Finally, the lack of definition precludes supply and demand analysis by heavy crude types, separating very heavy crudes such as Cold Lake from "lighter" heavy crudes such as Weyburn-Midale.

Such definitional variations limit the value of comparisons both between submissions, and with the actual NEB forecasts. Nevertheless, in the absence of alternative definitions, it is assumed the NEB definition as outlined in Chapter 1 was employed.

Similarly, the two price scenarios provided by the NEB to be used in the submissions were not always used by the submitters (see Table C.1). Some provided data for only one pricing scenario, while others considered alternative fiscal regimes rather than the status quo scenario requested by the NEB.

In addition, the submissions did not all adhere to the NEB (real) Canadian GNP growth projections either, generally anticipating lower growth rates (see Table C.2). Nevertheless, the general trend of long-term decreases in the GNP growth rate outlined in the NEB projections was followed.

Since these alternative assumptions cannot be easily conformed to the NEB's recommended scenario, and since many of the basic assumptions of the submissions are not specified, the available data are presented and compared assuming basic compatibility. Wherever possible, deviations from the NEB's recommendations are described, but in general, the NEB's scenario is assumed to hold.

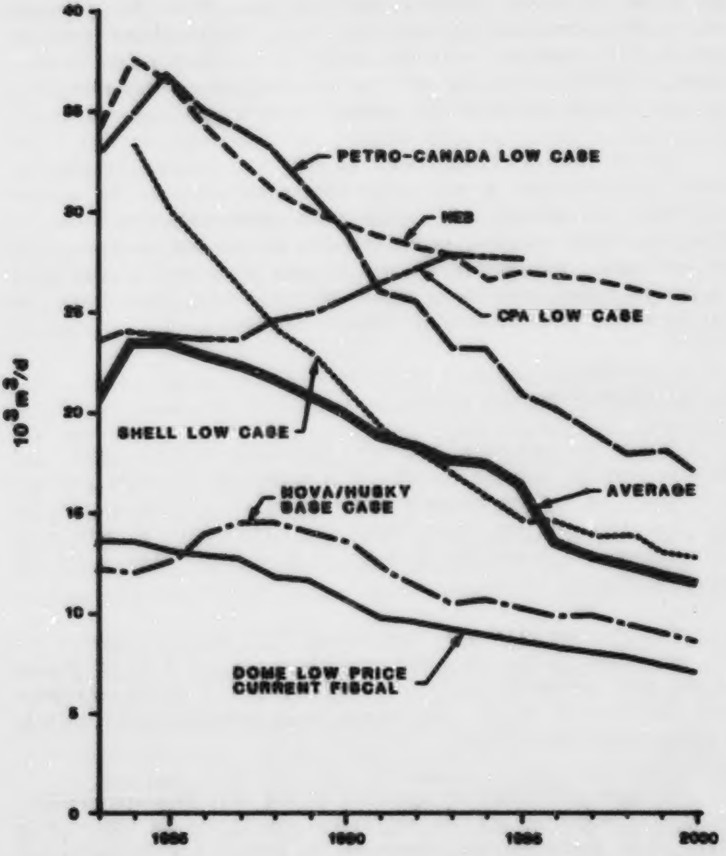
One final note of importance is that the averages of the submissions presented here do not always correspond with the NEB projections. This is accounted for in that other additional submissions, as well as the NEB's own data, were also used by the NEB in determining their forecasts. The submissions used in this study were largely those of major petroleum companies, which do not always agree with the generally conservative figures provided by the NEB.

4.2.1 Productive Capacity of Conventional Heavy Crude Oil

Figure 4.1 presents forecast conventional heavy crude oil productive capacity figures provided by a number of the major industry submissions. An average forecast based on these submissions and the actual NEB forecast are also depicted. PanCanadian's submission discusses heavy oil issues but includes no appropriate figures for the comparisons presented here.

The Canadian Petroleum Association (CPA) forecast assumes oil prices very close to the NEB's low price scenario and a fiscal regime improving only moderately. The forecast period for their submission extends only to 1995 because any longer range predictions are considered to be highly speculative.

The Dome submission provides one of the most detailed examinations of the impact of pricing and fiscal conditions on heavy crude supply. Four scenarios are presented by Dome: Low Price/Current Fiscal System, Low Price/Alternative Fiscal System, High Price/Current Fiscal System, and High Price/Alternative Fiscal System. Dome's view that supply is very sensitive to pricing and fiscal incentives is reflected in its range of supply projections: from a low for the year 2000 of 7100 cubic metres per day under the Low Price/Current Fiscal Regime to a high under the High Price/Alternative Fiscal Regime of 22 500 cubic metres per day for the same year (see Table C.3).



SOURCE: Table C.3.

NOTE: Low and base cases only. Dome forecast for current fiscal regime only.

FIGURE 4.1: FORECAST PRODUCTIVE CAPACITY OF CANADIAN CONVENTIONAL HEAVY CRUDE OIL: 1983-2000

The forecast provided in the joint submission by Husky and Nova uses their base case price estimates, assuming no increase after 1985 rather than the two NEB scenarios, but using the NEB assumption of continuation of the current fiscal regime. Slow economic growth rates, decreasing to 3 percent annually after 1987, are also assumed. Nova/Husky's supply projections include only Lloydminster area heavy crude from established reserves and reserves additions.

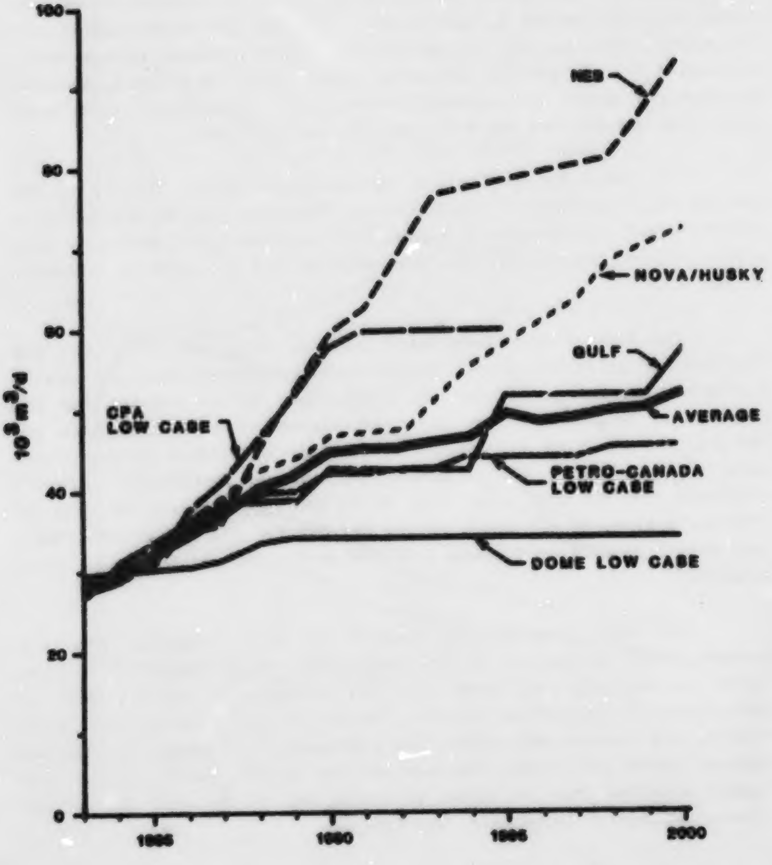
The Shell Canada Limited forecast uses prices similar to the NEB low price scenario. The productive capacity figures are based on Alberta's and Saskatchewan's established reserves plus additions from appreciations, new discoveries, and enhanced oil recovery as requested by the NEB.

The Petro-Canada submission provides forecasts under the NEB high and low price scenarios. Since their submission does not provide a complete breakdown of the low price case, it is assumed for the purposes of this report that their established reserves estimates are the same for the high and low cases, with the difference in productive capacity depending on the difference in reserves additions. Reserves additions for the high case rise to 21 000 cubic metres per day by 1999 but only to 12 400 cubic metres per day for the low case, largely as a result of smaller increases in EOR production under the low price scenario.

The wide discrepancies evident in these figures, even for current years, emphasize the difficulty in making comparisons. The lowest current figures, from Dome and Husky/Nova, exclude much of Saskatchewan's productive capacity, while the Petro-Canada and Shell figures were considerably higher and presumably more complete. The CPA figures, which fall midway between the two levels, were compiled from figures supplied from individual companies and may be lower than actual figures because of incomplete reporting.

4.2.2 Productive Capacity of Non-Conventional Heavy Crude Oil

Forecasts of total Canadian non-conventional heavy crude oil productive capacity were provided by the CPA, Dome, Gulf, Nova/Husky, and Petro-Canada submissions. All of these forecasts include both mineable oil sands productive capacity reported as volume of synthetic crude produced and bitumen from oil sands in-situ recovery projects (see Figure 4.2 and Table C.4). The former figures have not been



SOURCE: Table C.4.

NOTE: Low and base cases only. Dome forecast for current fiscal regime only. Average excludes NEB data.

FIGURE 4.2: FORECAST PRODUCTIVE CAPACITY OF CANADIAN NON-CONVENTIONAL HEAVY CRUDE OIL: 1983-2000

adjusted to reflect the larger input volumes required to produce synthetic crude.

The Canadian Petroleum Association's productive capacity forecasts for the oil sands indicate a substantial increase by 1995 due to Suncor and Syncrude expansion projects and the commencement of the Cold Lake and Wolf Lake projects, a new mining project, and experimental in-situ projects in the Peace River, Athabasca, Cold Lake, and Carbonate areas. These projections assume pricing close to the NEB suggested low price scenario.

Dome Petroleum provided forecasts under four price and fiscal regime scenarios as they did for conventional heavy crude. However, all four cases assume available markets for production, reasonable fiscal agreements, and all production receiving the world oil price.

Gulf Canada Limited's submission divides productive capacity forecasts of non-conventional crude oil into two sections: oil sands mining and in-situ. The sum of the two forecasts is used as a total forecast. The oil sands mining production forecast assumes only two plants, Suncor and Syncrude, up to 1990. The capacities of these plants are assumed to remain constant from 1990 to 2000 but additional production is forecast from three new mining projects.

Nova/Husky divide their forecast into two categories: non-mineable and mineable oil sands which are summed to provide a total forecast. Production of non-mineable oil sands is assumed to be from reservoirs located in the Cold Lake area, some portion of which will be developed as part of the Bi-Provincial Project--the Husky upgrader. The majority of forecast mineable oil sands production emanates from the Athabasca region.

Petro-Canada developed its forecasts according to the NEB high and low price scenarios. Petro-Canada forecasts two new oil sands mining projects during the forecast period if the high price scenario is combined with a fiscal regime similar to the one provided for the Wolf Lake project. However, these two potential projects would be uneconomic under the low price scenario situation.

In general, all the submissions expect considerable growth in Canadian non-conventional heavy crude productive capacity. The price of crude appears to be the primary factor affecting this capacity as high price scenarios indicate significantly larger increases.

Nevertheless, even the low price scenarios show stable, slightly increasing, productive capacity.

4.2.3 Productive Capacity of Total Heavy Crude Oil

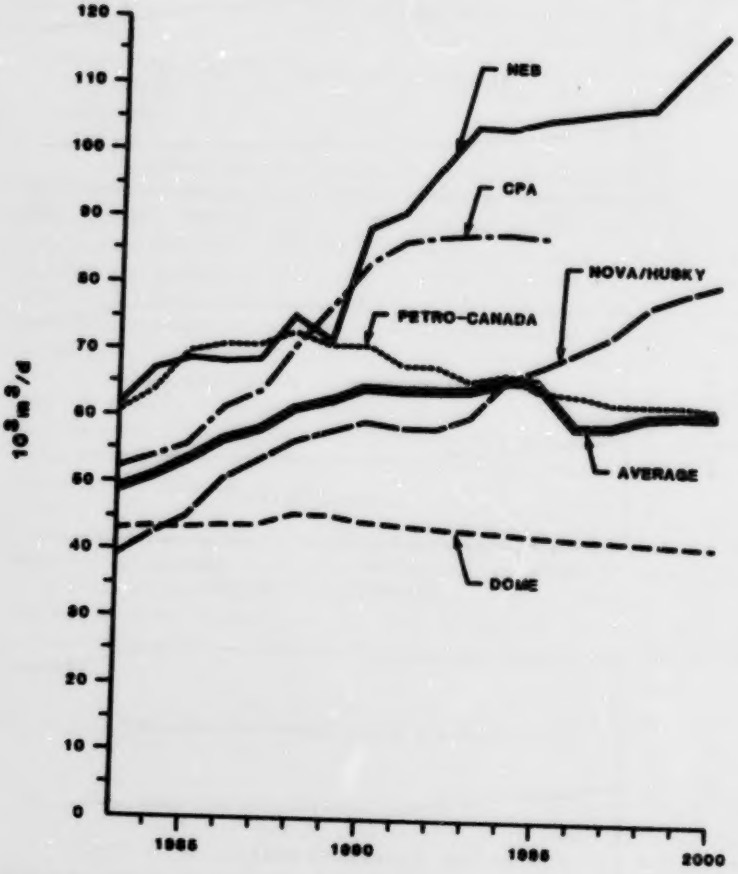
Forecast decreases in conventional heavy crude oil productive capacity will be more than offset by increases in non-conventional capacity resulting in an overall increasing trend in total heavy crude oil productive capacity to 1993, and slightly lower but increasing capacity thereafter (see Figure 4.3 and Table C.5). On average, total heavy crude productive capacity is forecast to increase some 1.4 percent per annum from 1983 to 2000.

4.3 Government Forecasts of Canadian Heavy Crude Oil Supply

4.3.1 Canadian Conventional Heavy Crude Oil Supply

In addition to industry supply forecasts, the Alberta Energy Resources Conservation Board and the Saskatchewan Department of Energy and Mines also provide remaining recoverable reserves and total productive capacity forecasts of Alberta conventional heavy crude oil and Saskatchewan heavy and medium crude oil (see Figure 4.4 and Tables C.6 and C.7).

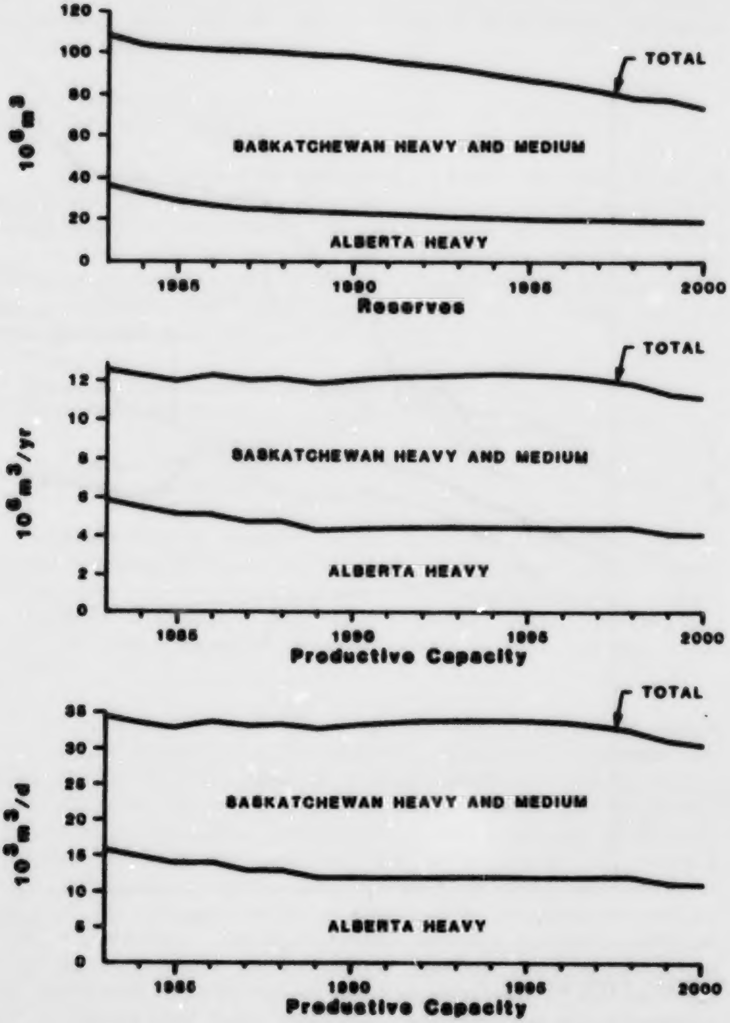
Alberta conventional heavy crude oil supply is forecast over a 25-year period during which the majority of reserves additions are assumed to take place. Assuming economic conditions similar to the present and no market constraints, the ERCB estimates that 80 percent of the ultimate potential conventional heavy crude oil discoveries and/or additions will take place over the NEB's 1983 to 2007 forecast period. Remaining recoverable reserves of 38 million cubic metres of heavy crude oil are expected to be recovered by means of primary and waterflood techniques. Although current tertiary recovery techniques may not be economically or technically feasible, more sophisticated future techniques are expected to yield an additional 75 million cubic metres of conventional heavy crude oil. Additions and new discoveries are forecast to add 35 million cubic metres to recoverable reserves, for a total remaining potential for conventional heavy crude oil of 148 million cubic metres as of December 31, 1982:



SOURCE: Table C.5.

NOTE: Low and base cases only.

FIGURE 4.3: FORECAST PRODUCTIVE CAPACITY OF TOTAL CANADIAN HEAVY CRUDE OIL: 1983-2000



SOURCE: Table C.6.

FIGURE 4.4: FORECAST RESERVES AND PRODUCTIVE CAPACITY OF ALBERTA CONVENTIONAL HEAVY CRUDE OIL AND SASKATCHEWAN HEAVY AND MEDIUM CRUDE OIL: 1983-2000

The ERCB forecast was generated using decline analysis in conjunction with historical pool productivity and engineering judgement to generate the forecasts. Although the Board realizes that reserves additions and productive capacity increases may occur at a faster rate in the presence of upgrading facilities in Alberta, the forecasts would not be significantly altered if such facilities were incorporated in the analysis.

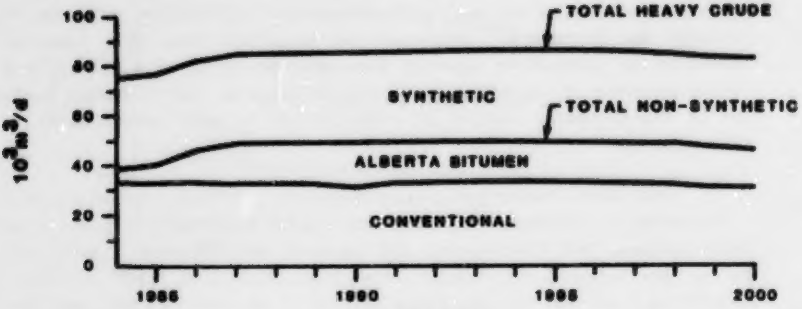
The Saskatchewan government forecasts are based on established reserves as of December 31, 1982 and future reserves additions from appreciations, new discoveries, and enhanced oil recovery. World oil prices are assumed to change only moderately from 1983 to 2005, decreasing 6 percent in real terms in 1984, 2 percent in 1985, and then remaining at zero real change for the rest of the forecast period. Canadian oil prices are assumed to be decontrolled by the end of 1986. In addition, the forecasts include a heavy crude oil upgrader in Regina with a capacity of 8 million cubic metres per day. Although a second upgrader in the Lloydminster area is expected in the near future, it is not represented in the forecast. The forecasts are mainly generated using decline curve analysis based on estimates from individual pools aggregated by pipeline system.

In general, the government forecasts corroborate those of the industry submissions indicating a decline in Canadian conventional heavy crude oil productive capacity through to 2000. However, the rate of decline in the former case is a mere 0.7 percent per year, while in the latter case average productive capacity decreases some 3.4 percent per year.

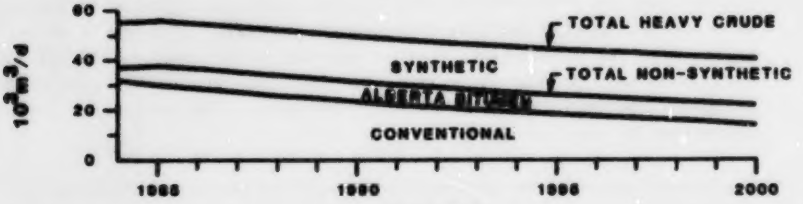
4.3.2 Total Canadian Heavy Crude Oil Supply

The government forecasts of total Canadian heavy crude oil supply concur with the submission forecasts in anticipating increasing total supply to about 1993 with slight decreases to the end of the forecast period (see Figure 4.5 and Tables C.8 to C.10). The high price case is the only exception to this rule in that increases are expected right to the year 2000.

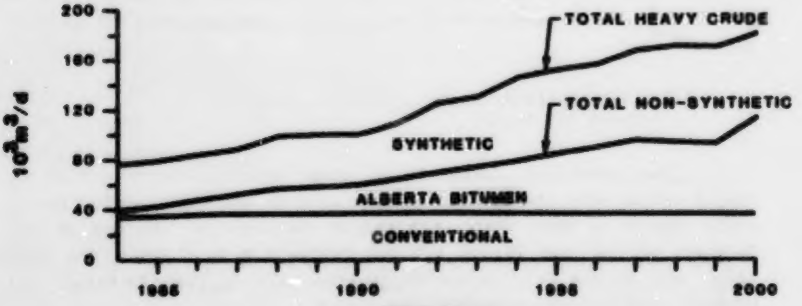
Initial differences between the three scenarios are due to differences in the assumed conventional crude oil recovery rates. Variations in later years are primarily attributable to differences in the assumed production of heavy oil from bitumen due to upgrading



Base Case



Low Case



High Case

SOURCES: Tables C.8 to C.10.

FIGURE 4.5: FORECAST ALBERTA AND SASKATCHEWAN TOTAL HEAVY CRUDE OIL SUPPLY: 1984 - 2000

developments. The low, base, and high cases include one, two, and three upgraders, respectively.

The level of synthetic crude oil production is also seen as price sensitive varying from only 50 percent of existing capacity in the low price case to including production from two additional plants in the high price case.

4.4 Demand Comparison, Synthesis, and Forecast

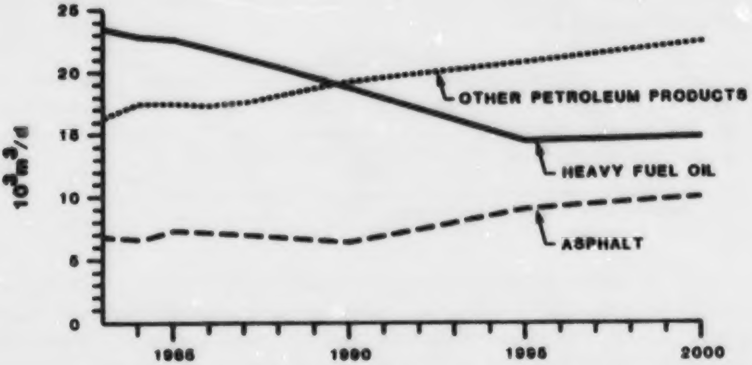
Canadian demand for Canadian heavy crude oil is a function of four other demands: heavy petroleum products demand, refinery feedstock demand, upgrader feedstock demand, and synthetic crude oil demand. Analysis of the individual factors and their sum will indicate total domestic demand for Canadian heavy crude oil.

4.4.1 Heavy Products Demand

Most of the submissions and studies reviewed provided demand forecasts for petroleum products. The analysis concentrates on asphalt and heavy fuel oil since the demand for these products will likely have the greatest impact on future demand for heavy crude oil.

4.4.1.1 Asphalt Demand

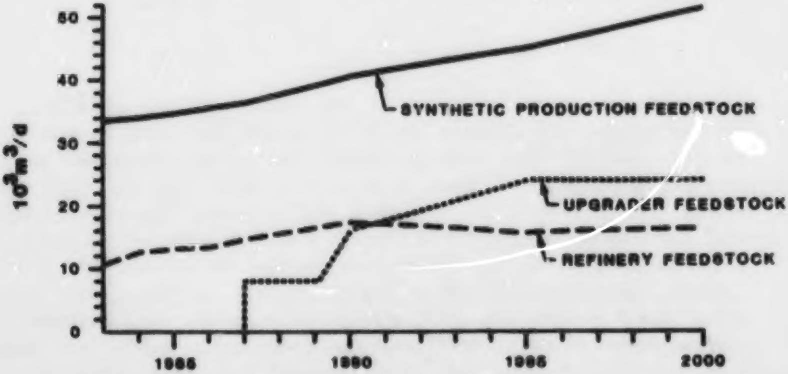
The majority of the studies and submissions reviewed foresee a relatively flat or slightly increasing demand for asphalt over the forecast period. The average demand for asphalt increases at an average annual rate of about 2 percent between 1983 and 2000 (see Figure 4.6 and Table C.11). However, the forecasts vary considerably, with Petro-Canada estimating an average annual increase of 5.3 percent, while Imperial Oil's figures show an average annual decrease of 0.8 percent. Nevertheless, most of the submissions indicate growth rates around the 2 percent per annum average which, given the importance of asphalt demand to the estimation of the Canadian demand for heavy crude oil, indicates a relatively stable demand for heavy crude oil in Canada.[1] Chapter 5 discusses the impact of U.S. asphalt demand on Canadian heavy crude oil.



SOURCES: Tables C.11, C.12, and C.14.

NOTE: Other Petroleum Products includes lubes and greases, naphtha specialties, petrochemical feedstocks, petroleum coke, and other miscellaneous products.

FIGURE 4.6: AVERAGE FORECAST CANADIAN DEMAND FOR ASPHALT, HEAVY FUEL OIL, AND OTHER PETROLEUM PRODUCTS: 1983-2000



SOURCES: Tables C.15, C.20, and C.21.

NOTE: Upgrader Feedstock based on CERI Base Case.

FIGURE 4.7: AVERAGE FORECAST CANADIAN DEMAND FOR CANADIAN HEAVY CRUDE OIL FOR REFINERY, UPGRADER, AND SYNTHETIC PRODUCTION FEEDSTOCK: 1983-2000

4.4.1.2 Heavy Fuel Oil Demand

The demand for heavy fuel oil is seen in all the studies and submissions to be falling (see Figure 4.6 and Table C.12). Heavy fuel oil demand declines in all sectors but transportation, where an average annual percentage increase of almost 2 percent is recorded over the forecast period (see Table C.13). The overall consensus is that heavy fuel oil will lose its market share over the forecast period, reflecting the general reduction in petroleum's share of the energy market. This change is largely a function of substitution for natural gas,[2] and will likely have an adverse effect on the already low Canadian demand for heavy crude oil as heavy fuel oil feedstock.[3]

4.4.2 Refinery Feedstock Demand

The relationship between forecast refinery demand for heavy crude oil as derived from refined petroleum products demand, and the general forecast for heavy crude oil demand is a close one.[4] In fact, these forecasts are sometimes believed to be sufficiently close to be almost interchangeable.

The total average Canadian demand for petroleum products which generally require heavy crude oil as feedstock (other than asphalt and heavy fuel oil which were discussed above) is forecast to increase at an average annual rate of almost 2 percent between 1983 and 2000 (see Figure 4.6 and Table C.14). This increase is corroborated by a total average annual increase of some 2.8 percent in Canadian refinery feedstock demand for Canadian heavy crude oil over the same period (see Figure 4.7 and Table C.15).

Projections of the latter demand are largely determined by expectations regarding refinery configuration and levels of imported crude oil feedstock. The relative impact of, and the interaction between these factors is evident in the forecasts of regional refinery feedstock demand (see Tables C.16 to C.19). The trends vary between regions, with Quebec and the Western provinces indicating increasing heavy crude oil refining capacity while Ontario decreases this capacity. The Atlantic provinces show no heavy crude oil capacity whatsoever, rather, indicating a fourfold increase in light crude oil capacity. The 3.5 percent average annual decrease in demand for imported crude oil feedstock, combined with the 2.8 percent per annum increase in demand for Canadian heavy crude feedstock and only marginal increases in light crude oil demand indicate that the overall increase in demand will be largely met by Canadian heavy crude oil (see Table C.15).

These overall trends are not followed by all the submissions due to different fundamental assumptions. For example, while Gulf foresees foreign feedstock being displaced by domestic feedstock from frontier production, Texaco does not concur.[5]

4.4.3 Upgrader Demand for Canadian Heavy Crude Oil

Almost all of the studies and submissions reviewed forecast the building of at least one upgrader in Canada by the late 1980s. However, the total number of upgraders estimated to be built over the entire forecast period ranged from one to four. These expectations resulted in forecasts of heavy crude oil demand for upgraders ranging from 8000 to 32 000 cubic metres per day by the end of the forecast period (see Table C.20). Overall, upgrader demand for heavy crude oil is forecast to increase at an average annual rate of over 5 percent from 1987 to reach 9300 cubic metres per day in the year 2000. Forecasts of further upgrader construction were largely confined to high price scenario forecasts, underlying the importance of price in upgrader economics.[6]

Recent decisions and developments relating to the building of upgrader facilities have resulted in the assumption that both the New Grade Energy Company Ltd. upgrader in Regina and the Husky upgrader (the Bi-Provincial project) will be built before the end of the 1980s, and that another upgrader will come onstream in the Cold Lake area in the mid-1990s.[7] Estimated upgrader demand for heavy crude oil related to this expected pattern of construction increases almost 9 percent per annum from 1987 to 2000 (see Figure 4.7 and Table C.20).

The construction of these three upgraders should have an important impact on the development of Alberta's bitumen resources. Even though the New Grade Energy Company upgrader will receive its supplies from the Lloydminster, Fosterton, and Weyburn/Midale streams,[8] it is expected that the other two upgraders will be largely dependent on production from the Cold Lake area. This situation reflects one of the positive side effects of upgrader construction: the development of Canadian heavy crude oil resources. For example, the construction of at least one of the proposed upgraders in Saskatchewan will mean "an assured market for Saskatchewan's crude systems and will assure the oil industry that exploration and development in the province will be viable for years to come."[9]

A second potential benefit of upgrader construction is the additional flexibility provided for refiners since upgraded heavy crude oil may be substituted for light crude oil feedstocks if the supply of light crude oil is diminished.[10]

One of the most important considerations affecting upgrading is the price differential for both crude oil and refined products. Three of the studies and submissions reviewed emphasized price differentials as the major factor in their estimations of the future potential for upgrader construction.[11]

Another significant factor in projections of upgrader construction is the prevailing fiscal regime. J. M. Wilkinson in "Introduction to Heavy Oil Upgrading" specifies the fiscal ingredients necessary for upgrader development: sufficient wellhead price after royalties to recover costs and provide adequate return on enhanced recovery; world price for upgraded crude; royalty and tax incentives to cover the cost of upgrading; and assurances that production of heavy oil upgrading will not be subject to prorationing.[12] The willingness of governments to meet these requirements might be gauged by reviewing the recent agreement made between Husky and the Alberta, Saskatchewan, and federal governments for the construction of Husky's Bi-Provincial upgrader.[13]

Finally, the effect of diluent supply on the question of upgrader construction is of equal, if not greater, importance than the issues discussed above. The outlook for diluent availability is discussed in Chapter 6.

4.4.4 Synthetic Production Demand

The final element in the Canadian demand for Canadian heavy crude oil is the requirements for synthetic production. Although the forecasts given by the various submissions differ considerably, the consensus opinion is for increasing heavy crude oil demand for use in synthetic crude production (see Figure 4.7 and Table C.21). The average annual increase from 1983 to 2000 is 2.5 percent, again indicating stable growth in demand for Canadian heavy crude oil.

4.4.5 Total Demand

Based on the aggregate of the above elements, the total Canadian demand for Canadian heavy crude oil is forecast to increase at an average annual rate of 4.4 percent from 1983 to 2000 (see Figure 4.8 and Table 4.1). Since the total average U.S. demand for Canadian heavy crude oil only increases by 2 percent annually (see Table C.22), this rate decreases slightly to 3.7 percent per annum when average U.S. demand is included. Nevertheless, demand for Canadian heavy crude oil is expected to experience stable, gradual growth to the end of the decade.

The NEB forecast total demand for Canadian heavy crude oil increases more rapidly, by more than 6 percent annually from 1983 to 2000. This is largely due to significantly larger synthetic feedstock requirements projected by the NEB.

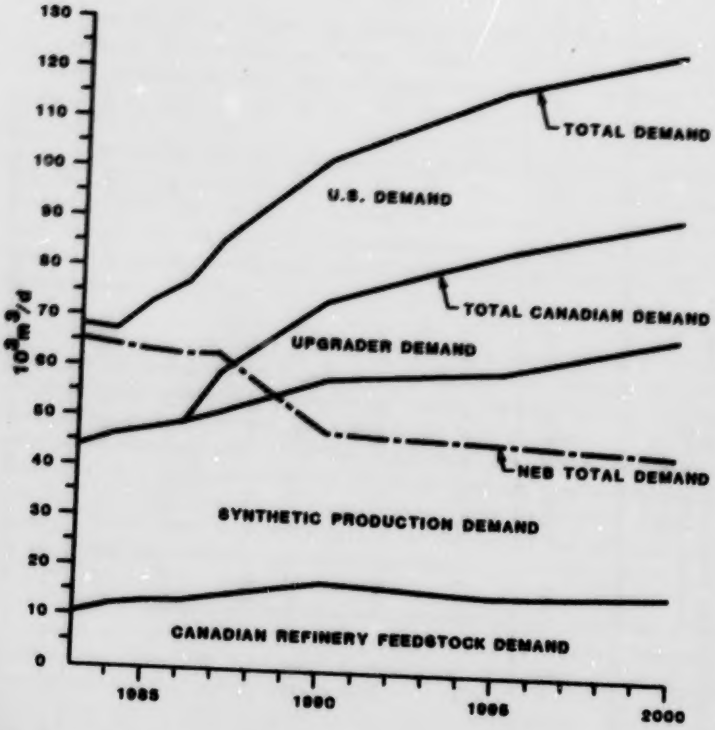
4.5 The Exportable Surplus of Canadian Heavy Crude Oil

Based on the above analysis, a synthesized forecast of the exportable surplus of Canadian heavy crude oil can be derived.

On the supply side, the government agency projections are used as being presumably more complete, and therefore more accurate. The low, base, and high supply cases, with one, two, and three upgraders, respectively, are used to provide low, base, and high case estimates of exportable surplus.

Total Canadian demand for Canadian heavy crude oil can be estimated in several ways. As previously mentioned, forecast refinery demand for heavy crude feedstock as derived from refined products demand is one method of estimating total demand for heavy crude. A second method is to forecast heavy crude oil nominations and multiply by the historical ratio of heavy crude oil nominations to heavy crude oil delivery figures. Finally, heavy crude oil exports (excluding the diluent compound) can be subtracted from heavy oil production figures to determine domestic demand for heavy crude oil.

Problems accompany all of these methods of demand estimation, the most serious being the lack of accurate, publicly available, actual delivery figures by refinery and crude type. Without accurate actual delivery figures, ratios between nominations and deliveries, and categorization of feedstocks into light and equivalent and heavy crude



SOURCE: Table 4.1.

NOTE: NEB figures based on Canadian refinery feedstock demand and U.S. demand only.

FIGURE 4.8:

SYNTHESIZED FORECAST OF CANADIAN AND TOTAL DEMAND FOR CANADIAN HEAVY CRUDE OIL: 1983-2000

TABLE 4.1

SYNTHESIZED FORECAST OF TOTAL DEMAND FOR CANADIAN HEAVY CRUDE OIL
1983-2000
($10^3 m^3/d$)

	1983	1984	1985	1986	1987	1990	1995	2000	Avg. Annual % Change 1983-2000
Canadian Refinery Feedstock Demand	10.5	12.6	13.2	13.6	14.5	17.6	15.7	16.7	2.8
Upgrader Demand	-	-	-	-	8.0	16.0	24.0	24.0	8.8
Synthetic Production Demand	33.7	34.0	34.7	35.5	36.7	40.6	45.0	51.7	2.5
Synthesized Forecast of Canadian Demand for Canadian Heavy Crude Oil	44.2	46.6	47.9	49.1	59.2	74.2	84.7	92.4	4.4
U.S. Demand	24.0	21.0	25.5	28.2	27.7	28.6	32.5	33.5	2.0
Synthesized Forecast of Total Demand for Canadian Heavy Crude Oil	68.2	67.6	73.4	77.3	86.9	102.8	117.2	125.9	3.7
NEB[a]	42.6	47.4	49.1	49.5	50.0	89.5	105.7	120.5	6.3

SOURCES: Tables C.15, C.20, C.21, and C.22.

[a] NEB figures based on Canadian refinery, upgrader, and synthetic feedstock demand only.

oil, classifications cannot be determined. Therefore, total Canadian demand for Canadian heavy crude oil is estimated by Canadian refinery demand for heavy crude oil feedstock.

On the demand side, the effect of upgraders on domestic demand is assessed by looking at total Canadian refinery feedstock and upgrader demand as well as at Canadian refinery feedstock demand alone.

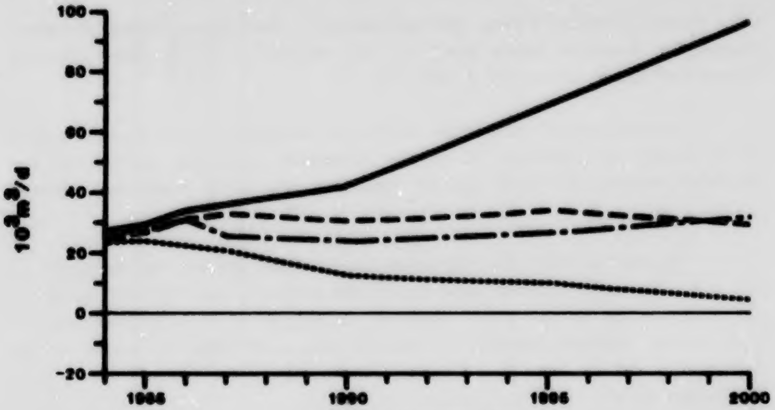
To the extent that upgraded heavy crude oil may be exported to the U.S., it may displace some light and medium crude oil which Canada currently sells to the U.S. However, conventional U.S. refineries can only accept limited amounts of upgraded heavy (synthetic) crude oil as feedstock which puts an upper limit on the effect of this displacement.

The net exportable surplus of Canadian heavy crude under these scenarios is presented in Figure 4.9 and Table 4.2. Because demand for domestic heavy crude oil increases at a much faster rate with upgraders than without--7.6 percent as opposed to 1.8 percent per annum--the exportable surplus when Canadian upgraders are built is lower and increases at a lower rate (as in the high case) or even declines (as in the low and base cases). Nevertheless, some exportable surplus of Canadian heavy crude oil still exists to the end of the forecast period in all cases but the low case with upgraders.

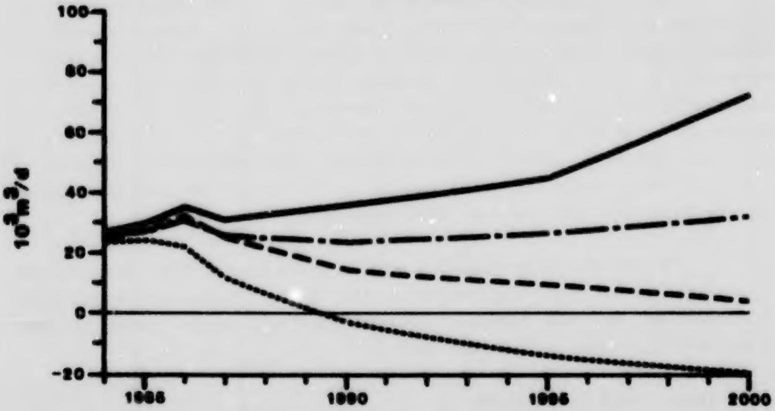
The NEB forecast compares most closely to the Base Case without upgraders due to the conservative nature of the forecast. Despite the differences, the NEB forecast corroborates the basic trend of some exportable surplus to the year 2000.

4.6 Summary and Conclusions

Analysis of various industry and government studies and submissions to the National Energy Board's update of its Canadian energy supply and demand forecast to the year 2000 has yielded a synthesized forecast of the supply of, demand for, and exportable surplus of Canadian heavy crude oil. This synthesized, or average, forecast provides an indication of likely future trends since it incorporates the views of several interest groups, notwithstanding some deviation from the price and fiscal system scenarios recommended by the NEB.



Without Upgraders



With Upgraders

LEGEND

NEB —·—
HIGH CASE ——
BASE CASE – – –
LOW CASE ··········

SOURCE: Table 4.2.

NOTE: The NEB does not provide different forecasts with and without upgraders. Low, base, and high cases include one, two, and three upgraders, respectively.

FIGURE 4.9: FORECAST EXPORTABLE SURPLUS OF CANADIAN HEAVY CRUDE OIL: 1984-2000

TABLE 4.2

SYNTHESIZED FORECAST OF EXPORTABLE SURPLUS OF CANADIAN HEAVY CRUDE OIL

1984–2000
($10^3m^3/d$)

	Supply[a]			Canadian Demand[b]		Exportable Surplus						NEB[c]
						Low Case		Base Case		High Case		
	Low Case	Base Case	High Case	Without Upgraders	With Upgraders	Without Upgraders	With Upgraders	Without Upgraders	With Upgraders	Without Upgraders	With Upgraders	
1984	36.6	38.8	39.8	12.6	12.6	24.0	24.0	26.2	26.2	27.2	27.2	34.6
1985	37.8	40.9	42.9	13.2	13.2	24.6	24.6	27.7	27.7	29.7	29.7	34.9
1986	36.2	46.7	48.7	13.6	13.6	22.6	22.6	33.1	33.1	35.1	35.1	34.9
1987	34.8	49.0	52.0	14.5	22.5	20.3	12.3	34.5	26.5	37.5	31.5	35.4
1990	31.1	49.2	60.2	17.6	33.6	13.5	(2.5)	31.6	15.6	42.6	36.6	21.3
1995	25.8	49.7	85.8	15.7	39.7	10.1	(13.9)	34.0	10.0	70.1	46.1	26.7
2000	21.8	46.6	113.8	16.7	40.7	5.1	(18.9)	29.9	5.9	97.1	73.1	30.9
Avg. Annual % Change 1984 - 2000	(3.2)	1.2	6.8	1.8	7.6	(9.2)	NA	0.8	(8.9)	8.3	6.4	(0.7)

SOURCES: (1) Tables C.8 to C.10 and 4.1; and (2) List of Studies and Submissions at the end of Appendix C.

[a] Low, base, and high cases assume one, two, and three upgraders, respectively.
[b] Canadian demand based on Canadian refinery feedstock demand.
[c] Excess supply over domestic refinery feedstock requirements.

On average, the industry forecast of the total productive capacity of Canadian heavy crude oil projects an increase of over 25 percent from 1983 to 2000, with increases in non-conventional capacity more than offsetting decreases in conventional heavy crude oil productive capacity. The base case projections of the Alberta and Saskatchewan governments support this general finding, with an overall increase of over 10 percent in heavy crude oil supply between 1984 and 2000. These latter projections are assumed to be more comprehensive in terms of their data inputs, and therefore are used in calculating the exportable surplus.

Heavy crude oil demand is determined by several factors including heavy petroleum products demand, refinery feedstock demand, upgrader demand, and synthetic production demand. Total demand for heavy petroleum products is forecast to remain generally stable as declines in heavy fuel oil demand are balanced out by increases in demand for asphalt and other products. Refinery, upgrader, and synthetic production feedstock demand are all expected to increase to the year 2000, resulting in an average annual increase of 4.4 percent in total Canadian demand for Canadian heavy crude oil. U.S. demand for Canadian heavy crude oil is also projected to increase on average, albeit at a slower rate, yielding an overall annual increase of 3.7 percent in total demand for Canadian heavy crude oil.

The forecast exportable surplus of Canadian heavy crude oil was determined by subtracting Canadian refinery feedstock demand (which serves as a close approximation of total demand) from the governments' Canadian heavy crude oil supply forecast. All but one of the low, base, and high cases, both with and without upgraders, project some exportable surplus to the end of the forecast period. Moreover, in half of the six cases the exportable surplus shows a net increase from 1984 to 2000.

Given this conclusion, it is appropriate to assess the most likely market for this surplus, and the capacity of that market to absorb Canadian heavy crude oil. Chapter 5 to follow will evaluate the U.S. market in terms of its potential demand for the exportable surplus of Canadian heavy crude oil.

Footnotes

[1] Almost all studies and submissions reviewed suggested that of all petroleum products, the demand for asphalt would be the most indicative of the character and have the greatest impact on the demand for heavy oil. In fact, the Gulf submission to the NEB suggested that "the forecast of indigenous heavy crude oil requirements is strictly a function of the demand for asphalt," and that any increase in the demand for asphalt would come from the paving rather than the roofing sector. See Gulf Canada Limited, "Canadian Energy Supply and Demand 1983-2000: Submission to the National Energy Board in the Matter of the 1984 Energy Supply and Demand Update," February 1984, pp. 24 and 26.

[2] Canadian Petroleum Association, "Update of Canadian Energy Supply/Demand" (Calgary: Canadian Petroleum Association, February 1984), p. 16; and Texaco Canada Inc., "Submission to the National Energy Board: Update of Energy Supply and Demand 1982-1995," February 1984, pp. 7 and 13.

[3] Imperial Oil Limited, "Submission to the National Energy Board: In the Matter of Canada's Long-Term Energy Supply and Demand," February 1984, p. 29.

[4] Foster Research used an average of the figures provided by four of the submissions presented in Table C.15 as well as other requirements projections and a 1983 government agency estimate to produce its estimates of Canadian heavy crude oil requirements. See Foster Research, The Forecast Supply and Demand for Alberta Condensate for Blending with Heavy Crude Oil 1984-2000 (Calgary: Foster Research, 1984), p. 15.

[5] Gulf Canada Limited, "Canadian Energy Supply and Demand 1983-2000: Submission to the National Energy Board in the Matter of the 1984 Energy Supply and Demand Update," February 1984, p. 24; and Texaco Canada Inc., "Submission to the National Energy Board: Update of Energy Supply and Demand 1982-1995," February 1984, p. 4.

[6] Two submitters and one research group emphasized the difficulties currently involved in upgrader construction. See Amoco Petroleum Ltd., "Submission to the National Energy Board, Energy Supply and Demand 1984-2005," (Calgary: Amoco Canada Petroleum Company Limited, 1984), p. 14; Petro-Canada, "Submission to the National Energy Board Update of Energy Supply and Demand, 1983 to 2005," January 1984, p. 102; and Foster Research, The Forecast Supply and Demand for Alberta Condensate for Blending with Heavy Crude Oil 1984-2000, p. 27.

[7] According to industry sources, it is quite likely that Esso will build an upgrader in the Cold Lake area. In addition, it has been rumoured that Shell also intends to build an upgrader. If constructed, these two upgraders are expected to come onstream in 1994 and 1996, respectively.

[8] Foster Research, The Forecast Supply and Demand for Alberta Condensate for Blending with Heavy Crude Oil 1984-2000, p. 22.

[9] "Greater Stability for Heavy Oil Industry," Energy Analects, September 2, 1983, pp. 1-2.

[10] "Surge of U.S. Refinery Upgrading Trims Heavy Feed, Boosts Prices," Oil and Gas Journal, April 30, 1984, p. 21.

[11] Amoco Canada Company Petroleum Ltd., "Submission to the National Energy Board, Energy Supply and Demand 1984-2000," p. 14; Petro-Canada, "Submission to the National Energy Board Update of Energy Supply and Demand, 1983 to 2005," January 1984, p. 102; and Foster Research, The Forecast Supply and Demand for Alberta Condensate for Blending with Heavy Crude Oil 1984-2000, p. 27.

[12] J. M. Wilkinson, "Introduction to Heavy Oil Upgrading" in The Future of Heavy Crude and Tar Sands: First International Conference, edited by R. F. Meyer and C. T. Steele (New York: McGraw-Hill Inc., 1981), p. 602.

[13] "Husky Upgrader Gets the Green Light," Oilweek, June 11, 1984, p. 8:

> The fiscal package includes a $50 million grant from the federal government to help defray costs during the construction phase of the upgrader, plus a $780 million loan guarantee and no PGRT will be payable until project payout. The Alberta government will provide a loan guarantee of up to $390 million and a royalty regime comparable to those granted to the recent oil sands projects, phased royalties of 1 to 5 percent to payout, including a return allowance, then a profit sharing arrangement after payout. Saskatchewan will also provide a loan guarantee up to $390 million and a graduated royalty regime which will include a royalty of 1 to 5 percent for feedstock from new EOR projects, current royalty for existing EOR projects, while existing primary production will have a credit system with 33 percent of current royalties flowing back into the project. New primary production will have a phased in rate of 1 to 10 percent. The agreement provides for the upgrader's production to receive NORP and, prior to the upgrader coming onstream, all oil dedicated to the project will also receive NORP.

Chapter 5

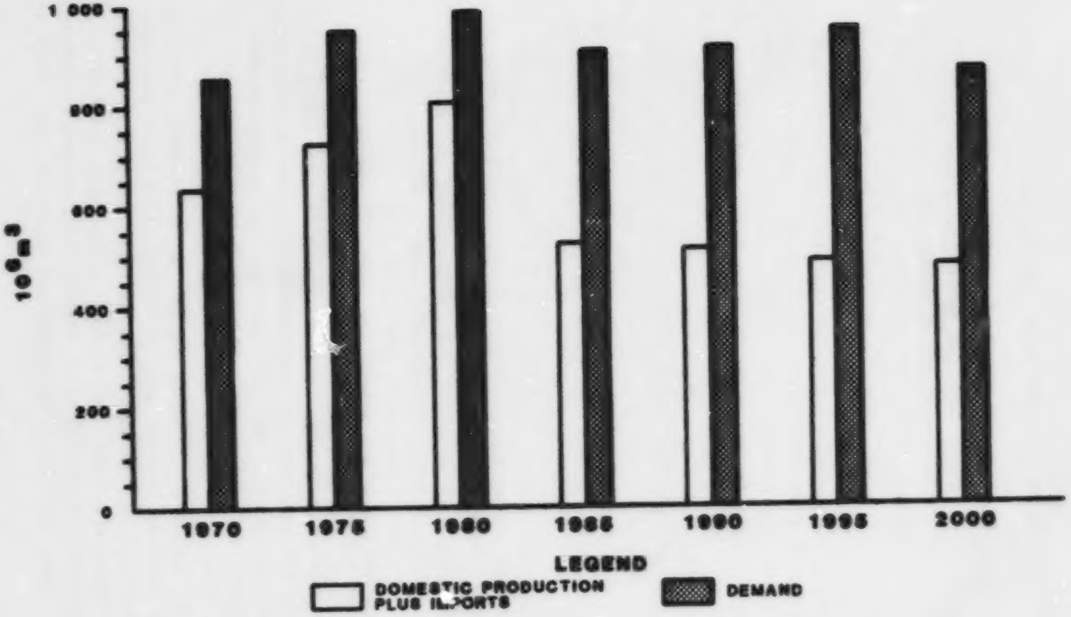
CANADIAN PENETRATION OF THE UNITED STATES HEAVY CRUDE OIL MARKET: DETERMINANTS AND PROSPECTS

5.1 Introduction

Previous chapters have indicated that both the world crude oil market, in terms of a widening long-term crude oil price differential, and the Canadian heavy crude oil market, in terms of projected exportable surplus, are conducive for Canadian heavy crude oil exports. Moreover, analysis of historical data has revealed the growing importance of the United States as a major importer of Canadian heavy crude oil. In fact, the available evidence points to a definite potential for the expansion of U.S. markets for Canadian heavy crude oil. Over the medium term (to 1988), demand for paving asphalt in particular could be a major source of derived demand for Canadian heavy crude oil, as it is the primary feedstock used to produce asphalt for export. Thus, the following sections will focus on U.S. crude oil supply and demand, historical production, consumption and imports of heavy oil, and the potential demand for Canadian heavy crude oil. In particular, the market potential in northern U.S. states will be examined to determine the market interface for Canadian heavy crude oil.

5.2 U.S. Crude Oil Supply and Demand

U.S. domestic crude oil supply declined during the early seventies while imports rose due to unfavourable regulations, controlled domestic crude oil prices, and the depletion of already discovered pools (see Figure 5.1 and Table D.1). As well, offshore oil was comparatively cheaper to produce and afforded opportunities for wider refinery profit margins. However, as foreign governments increased their share of revenues from the sale of oil and the federal government began to react to U.S. dependence on imported, relatively insecure supplies of crude oil, the environment became more conducive to domestic production, especially from higher cost, marginal sources. Thus, after a short decline, U.S. production began to rise again by 1982.



SOURCE: Table D.1.

NOTE: Total supply approximated by domestic production plus imports. Import data not available after 1982.

FIGURE 5.1: U.S. CRUDE OIL SUPPLY AND DEMAND: 1970-2000

The importance placed on security of supply will continue to encourage increased domestic production in the short term, but reserves limitations will likely reverse that trend by 1990 (see Figure 5.1 and Table D.1). Because of this decline, U.S. demand for crude oil will continue to exceed domestic supply, although the magnitude of this deficit is not generally agreed upon.[1] As with supply, demand predictions are largely affected by anticipated changes in world crude oil prices. Nevertheless, recent government and private sector projections for demand over the long term generally conclude that U.S. crude oil demand will trend downward over the next 15 years on a per-unit real value of GNP basis.

Despite this decrease in demand, the U.S. will necessarily continue to be a major importer of petroleum until the year 2000 to satisfy domestic demand.[2] In fact, if the economy continues its present trend of high GNP growth, the volume of crude imports will rise.

This broad demand picture is not overly informative, for changes in specific end-use markets can greatly affect the products demand mix and, therefore, the crude feedstock demand. Over the longer term, only uses that are specific to the particular form and characteristics of various grades of crude oil will remain economic.[3] For example, liquid fuel for transportation purposes will increasingly tax available supplies of lighter crude feedstock, more so than other end-uses that can economically and efficiently substitute other primary energy inputs.[4] Nevertheless, as light crudes become increasingly costly to use as feedstock, heavy crude oil will play a greater role in making such fuels, initially in mixes with lighter crudes, and then as a feedstock in its own right as new technology is adopted at refineries on an industry-wide basis. While conservation in the transportation sector will continue to stabilize fuel demand, the basic pattern of crude oil use will make increased use of heavy crude oil inevitable.

5.3 United States Policy and Regulatory Environment

Since the promulgation of the Merchant Marine Act in 1920, U.S. federal legislation and overall policy has had profound effects on its oil and gas industry in general, and on its refining sector in particular.[5] Legislation passed in the mid-1970s encouraged the building of small, comparatively unsophisticated refineries and simultaneously depressed the price of heavy crude oil.[6] Market disruptions of this kind provided the major impetus for the National Energy Plan (NEP), and later the National Energy Policy Plan (NEPP). The NEP, in turn, has initiated a substantial restructuring of the U.S. refining industry.

5.3.1 The National Energy Act

Title VIII of the Department of Energy Organization Act requires the President to submit to Congress biennially a National Energy Policy Plan,[7] the first of which was submitted in 1977.

The singular purpose of the NEPP was to reduce oil imports by:

- replacing oil and gas in industrial and utility end-uses with other fuels (e.g., coal),
- improving the efficiency of energy use,
- adjusting pricing policies to increase domestic production from conventional sources, and
- providing a basis for the development of alternative energy sources.[8]

Five subsidiary pieces of legislation covering energy conservation, fuel use, public utilities, natural gas, and energy taxes were passed simultaneously in 1978. These bills were to reduce oil imports by a total of 380 to 469 million cubic metres per day by 1985.

5.3.2 The National Energy Policy Plans

Despite the fact that they were prepared under different administrations, NEPP 1979 and NEPP 1981 are quite similar, the major policy objective of both being the reduction of U.S. dependence on foreign oil and hence its vulnerability to external supply shocks. The primary method used to achieve this goal was the removal of government restrictions on energy prices.[9] By increasing the average price of crude oil, these decontrols effectively removed the price subsidy on imported crude oil. Overall, decontrols were expected to have the dual effects of reducing U.S. crude oil imports and increasing domestic production.[10] This policy was reinforced by NEPP 1981 with a firm commitment to price decontrol by 1981. As well, a Windfall Profits Tax was proposed to prevent excess benefits to producers from decontrol.

Neither document deals directly with the role of heavy crudes. NEPP 1979 mentions this energy source only descriptively, emphasizing that actual recoverable reserves depend on technology, production costs, oil prices, and market developments.[11] These comments reflect the marginal status of heavy crude oil as an energy source at that time but indicate the anticipation of a more important role in the future. In fact, NEPP 1981 suggested that refineries be expanded and upgraded to process lower quality crudes according to its predictions of shortages of unleaded fuel "in the near future." It was recognized that investments along this line had been discouraged in the past by government regulations that reduced returns.[12]

Between NEPP 1981 and NEPP 1983 economic conditions, and hence policy imperatives, changed considerably. Price and allocation controls on crude oil, which began to be phased out in 1979, were removed completely by Executive Order in January 1981.[13] Under then-current demand conditions, investment in exploration and development increased, as did activity dedicated to expanding production from established sources.

From 1973 to 1983, residential/commercial energy consumption dropped 20 percent, energy consumption per capita fell 13 percent, energy input per unit of industrial output decreased 23 percent, energy consumption per dollar of GNP fell 19 percent, and fuel use per vehicle decreased 20 percent.[14] Moreover, world oil prices had declined and dependence on foreign oil had been substantially reduced, as had vulnerability to supply disruption. Thus, the NEPP 1983 policy goal was "an adequate supply of energy at reasonable costs." Government intervention, once thought to be a necessity, was to be kept to a minimum except where "non-monetary costs to society as a whole" were concerned. Thus, NEPP 1983 incorporated two key initiatives: the deregulation of natural gas wellhead prices and adjustment of control provisions made under a more regulated regime, and reforms in the nuclear energy sector.

With respect to energy trade, the latest NEPP reflects a firm commitment to creating a "free-market environment" in the interests of economic efficiency. Projections for economic growth and trends in energy demand are such that net crude oil imports as a proportion of total energy consumption should remain stable at 1982 levels of 12 percent, or 684 000 cubic metres per day in 1982, and 759 000 cubic metres per day in 2000.[15]

5.4 U.S. Demand for Heavy Crude Oil

5.4.1 Refinery Demand

Such free market policy bodes well for increased Canadian crude oil exports to the United States. In particular, the market for Canadian heavy crude oil could be quite promising since many U.S. refineries that process bottoms and heavy crude oils have actually increased their capacity in the past few years.[16] In the U.S. as a whole, solvent extraction processing to make residual and heavy crude oils more suitable as conversion feedstocks increased 25 percent from 1982 to amount to some 45 000 cubic metres per day as of January 1984.[17] Although recent crude oil price differentials have not been sufficient to assure adequate returns to refiners who have upgraded their plants in order to process heavy crudes, in the long term these refiners will likely be in a position of advantage over those who will not be able to choose crude oil feedstock from a wide variety of sources.[18]

Although data are not available on the disposition of domestic heavy crudes among refiners, some insight into the patterns of demand for heavy crude refinery feedstocks can be obtained by examining statistics on heavy crude oil imports. In general, U.S. refinery heavy crude oil imports have increased over time such that 1983 volumes were almost twice as much as those in 1979 (see Table 5.1). Recent month-to-month data show that import volumes are steadily strengthening with quantities for the first and second quarters of 1984 being 52 percent and 25 percent above those for the same periods in 1983. Canada's share of total U.S. imports has maintained pace with these increases with the absolute volume also doubling between 1979 and 1983.

While the actual ports of entry (including pipeline terminals) for all imported heavy crude oil from 1979 to 1984 were dispersed throughout all the PAD districts, almost 100 percent of the refineries receiving this crude are located in PADDs I and II (see Tables 5.1 and 5.2). Although transfers between refineries and PADDs cannot be identified, the data indicate that PADDs IV and V use their own imports, while PADD III transfers all of its imports to PADDs I and II. PADD II brings in imports from PADD III, and sometimes from PADD I as well. Finally, PADD I alternatively receives imported crude from other PADDs and transports some of its own imports to other PADDs.

TABLE 5.1

U.S. REFINERY RECEIPTS OF IMPORTED HEAVY CRUDE OIL BY PORT OF ENTRY[a]
1979-1984
($10^3 m^3$)

Port of Entry	1979	1980	1981	1982	1983	1984[b]
PADD I						
Buffalo, New York	44.2	305.9	43.4	-	141.2	-
New York, New York	-	-	-	-	67.5	-
Philadelphia, Penn.	-	-	-	-	-	72.9
West Seneca, New York	-	-	-	-	-	0.2
Total	44.2	305.9	43.4	-	208.7	73.1
Canadian Imports	44.2	305.9	43.4	-	208.7	0.2
PADD II						
Bay City, Mich.	-	-	-	-	-	46.3
Chicago, Ill.	461.3	1 403.3	596.6	1 714.9	4 045.5	3 419.2
Coutts, N.D.	-	-	-	-	-	39.9
Duluth, Minn.	4 741.6	4 017.7	4 861.4	6 806.4	6 810.8	5 502.5
Findlay, Ohio	21.5	-	-	-	-	-
Griffith, Ind.	0.7	-	-	-	-	-
Mahomet, Ill.	97.1	-	-	-	-	-
Portal, N.D.	91.2	-	-	-	-	-
Port Huron, Mich.	142.8	-	-	-	10.3	-
Sarnia, Mich.	-	-	-	-	143.4	-
Superior, Wis.	466.2	295.7	273.0	290.8	254.5	213.5
Toledo, Ohio	-	-	31.9	-	5.9	20.4
Total	6 022.4	5 716.7	5 762.9	8 812.1	11 270.4	9 241.7
Canadian Imports	6 022.4	5 716.7	5 762.9	8 812.1	11 270.4	9 241.8
PADD III						
Baton Rouge, La.	-	173.4	20.6	-	-	-
Beaumont, Texas	464.1	319.4	-	1 126.9	1 064.9	205.9
Gramercy, La.	-	161.0	313.5	492.0	711.4	813.1
Nederland, Texas	546.4	531.6	58.1	-	-	-

Continued on Next Page

TABLE 5.1 (Continued)

Port of Entry	1979	1980	1981	1982	1983	1984[b]
PADD III (Continued)						
New Orleans, La.	544.0	1 380.5	577.1	621.9	713.7	706.7
Port Arthur, Texas	-	20.0	48.9	-	-	-
Smith Bluffs, Texas	-	-	-	-	206.0	141.8
St. James, La.	-	127.3	572.9	169.9	90.6	585.6
Total	1 554.5	2 713.2	1 591.1	2 410.7	2 786.6	2 433.6
Canadian Imports	-	-	-	-	11.2	-
PADD IV						
Cutbank, Mont.	9.9	-	-	209.1	594.5	266.8
Sweetgrass, Mont.	-	-	-	12.3	0.6	11.0
Total	9.9	-	-	221.4	595.1	277.8
Canadian Imports	9.9	-	-	221.4	595.1	277.8
PADD V						
Anacortes, Wash.	19.9	-	-	42.9	66.4	-
Total	19.9	-	-	42.9	66.4	-
Canadian Imports	19.9	-	-	-	-	-
TOTAL[c]	7 650.9	8 735.8	7 397.4	11 487.1	14 927.2	12 045.8
Canadian Imports	6 096.4	6 022.6	5 806.3	9 033.5	12 085.4	9 519.7
Canadian/Total Imports (%)	79.7	68.9	78.5	78.6	81.0	79.0

SOURCE: American Petroleum Institute, Imported Crude Oil and Petroleum Products Reports (Database).

[a] Heavy crude oil defined as less than or equal to 29° API. Port of Entry includes pipeline terminals.

[b] 1984 data includes first eleven months only.

[c] Discrepancies in totals between Tables 5.1 and 5.2 due to rounding.

TABLE 5.2

U.S. REFINERY RECEIPTS OF IMPORTED HEAVY CRUDE OIL BY REFINERY[a]
1979–1984
($10^3 m^3$)

Refiner/Location	1979	1980	1981	1982	1983	1984[b]
PADD I						
Ashland/Buffalo, New York	44.2	495.0	291.5	15.9	-	-
Mobil/Buffalo, New York	-	155.2	12.1	-	-	-
United/Warren, Penn.	-	103.6	-	55.6	352.0	0.2
Total	44.2	753.8	303.6	71.5	352.0	0.2
Canadian Imports	44.2	315.1	43.4	-	352.0	0.2
Canadian/Total Imports (%)	100.0	41.8	14.3	-	100.0	100.0
PADD II						
Amoco/Mandan, N.D.	91.2	-	-	-	-	-
Amoco/Whiting, Ind.	231.5	-	198.6	215.1	1 213.6	987.9
Ashland/Findlay, Ohio	210.6	212.0	4.2	-	-	-
Ashland/St. Paul Park, Minn.	651.3	445.2	125.0	151.8	125.1	86.5
Gladieux/Ft. Wayne, Ind.	-	-	-	90.7	81.4	31.7
Koch/Pine Bend, Minn.	4 186.8	4 254.2	4 877.0	6 927.1	7 312.8	5 841.1
Laketon/Laketon, Ind.	0.7	0.9	-	-	-	-
Marathon/Detroit, Mich.	-	55.9	36.9	198.3	850.4	558.7
Marathon/Joliet, Ill.	0.4	-	-	-	-	-
Marathon/Robinson, Ill.	277.4	175.7	81.4	692.7	627.4	461.5
Mobil/Joliet, Ill.	210.8	1 765.2	1 250.5	2 189.8	2 728.6	2 311.8
Murphy/Superior, Wis.	466.2	295.7	273.0	290.8	254.5	213.5
Sohio/Toledo, Ohio	165.3	-	-	215.8	156.6	302.6
State/Toledo, Ohio	47.4	-	-	-	-	-
Sun/Toledo,Ohio	819.5	548.0	31.9	-	16.2	20.4
Total/Alma, Mich.	-	16.2	-	-	-	46.3
Union/Lemont, Ill.	154.5	213.0	215.2	179.4	546.9	905.7
Total	7 576.7	7 983.0	7 093.7	11 151.5	13 913.5	11 767.7
Canadian Imports	6 022.5	5 707.5	5 762.8	8 812.1	11 138.3	9 241.9
Canadian/Total Imports (%)	79.5	71.5	81.2	78.9	80.1	78.5

Continued on Next Page

TABLE 5.2 (Continued)

Refiner/Location	1979	1980	1981	1982	1983	1984[b]
PADD IV						
Cenex/Laurel, Mont.	-	-	-	132.9	430.4	277.9
Conoco/Billings, Mont.	-	-	-	76.1	164.1	-
Flying J./Cutbank, Mont.	-	-	-	12.3	0.6	-
Simmons/Great Falls, Mont.	9.9	-	-	-	-	-
Total	9.9	-	-	221.3	595.1	277.9
Canadian Imports	9.9	-	-	221.3	595.1	277.9
Canadian/Total Imports (%)	100.0	-	-	100.0	100.0	100.0
PADD V						
Shell/Anacortes, Wash.	-	-	-	-	66.4	-
Texaco/Anacortes, Wash.	19.9	-	-	42.9	-	-
Total	19.9	-	-	42.9	66.4	-
Canadian Imports	19.9	-	-	-	-	-
Canadian/Total Imports (%)	100.0	-	-	-	-	-
TOTAL[c]	7 650.7	8 735.8	7 397.3	11 487.2	14 927.0	12 045.8
Canadian Imports	6 096.4	6 022.6	5 806.3	9 833.5	12 085.4	9 519.7
Canadian/Total Imports (%)	79.7	68.9	78.5	78.6	81.0	79.0

SOURCE: American Petroleum Institute, Imported Crude Oil and Petroleum Products Reports (Database).

[a] Heavy crude oil defined as less than or equal to 29° API.
[b] 1984 data includes first eleven months only.
[c] Discrepancies in totals between Tables 5.1 and 5.2 due to rounding.

The pattern of ports of entry and refinery receipts of Canadian heavy crude oil is similar to that of total imported heavy crude oil receipts. PADD I refineries generally use as much heavy crude oil as PADD I receipts of Canadian heavy crude oil. PADD II imports Canadian heavy crude oil exclusively with its refiners using as much as, or slightly less than, these volumes. Canadian to total heavy crude oil receipts by PADD II refineries have varied from 72 to 81 percent from 1979 to 1983. PADDs III and V have received minor amounts of Canadian heavy crude oil over the same period but only two PADD V refineries received some portion of these volumes. Finally, all PADD IV imports and refinery receipts of heavy crude oil are from Canada.

Based on ports of entry and refinery demand for imported Canadian heavy crude oil, PADDs I and II are the most likely markets for further sales of Canadian heavy crude oil into the United States. Thus, the discussion of the U.S. market interface for Canadian heavy crude oil will focus on these districts.

5.4.2 Asphalt Demand

In addition to a favourable government policy and refinery capacity environment, recent U.S. federal and state initiatives to upgrade, repair, and extend the U.S. interstate highway system provide potential derived demand for Canadian heavy crude oil exports through increased U.S. asphalt demand. This impact could be felt either through direct exports of asphalt, or through heavy crude oil and/or bitumen exports as feedstock for asphalt production.

Federal funding of interstate highways began in 1956 when the Highway Trust Fund (HTF) was established to provide federal funds for highway building and repair. Since then, an average of $4 billion (nominal) has been spent each year from the HTF under the auspices of the Federal Highway Administration (FHA).[19]

The Surface Transportation Assistance (STA) Act was enacted on January 6, 1983[20] to repair and extend existing interstate highway systems. However, most of the annual allotments of $10 to $11 billion are designated for major new construction or reconstruction rather than on regular maintenance.

Allocation to states from the HTF for 1982 amounted to $7.6 billion. Under the STA Act, the 1983 budget raised this figure to nearly $13 billion, financed by a 5 cents per gallon (1.3 cents per litre) gasoline tax and an increase in heavy truck user fees. It is expected that as much as $5.5 billion will be raised from these sources annually.[21]

On average, state governments will be eligible to receive 43 percent more federal funds for highway construction than previously, based on the existing number of highway miles, population, and highway traffic volumes in each state.[22] Funds are released on a 10 percent/90 percent state/federal basis such that a state will only receive nine times its own budget for highways, up to its maximum allotment.

During the first eleven months of 1983, states awarded highway construction contracts worth 30 percent more than during the same period in 1982. Some $8.9 billion worth of projects was approved for contract bidding by the FHA, an increase of 60 percent over 1982.

Because of the incentive states have to allocate funds to interstate highway projects, state expenditures have shifted away from intrastate projects. A total of $432 million less was spent on intrastate road building and maintenance in 1983 than during 1982.[23] Nevertheless, several states have been motivated by both deteriorating highways and the STA Act initiative to embark on ambitious intrastate programs of their own.[24]

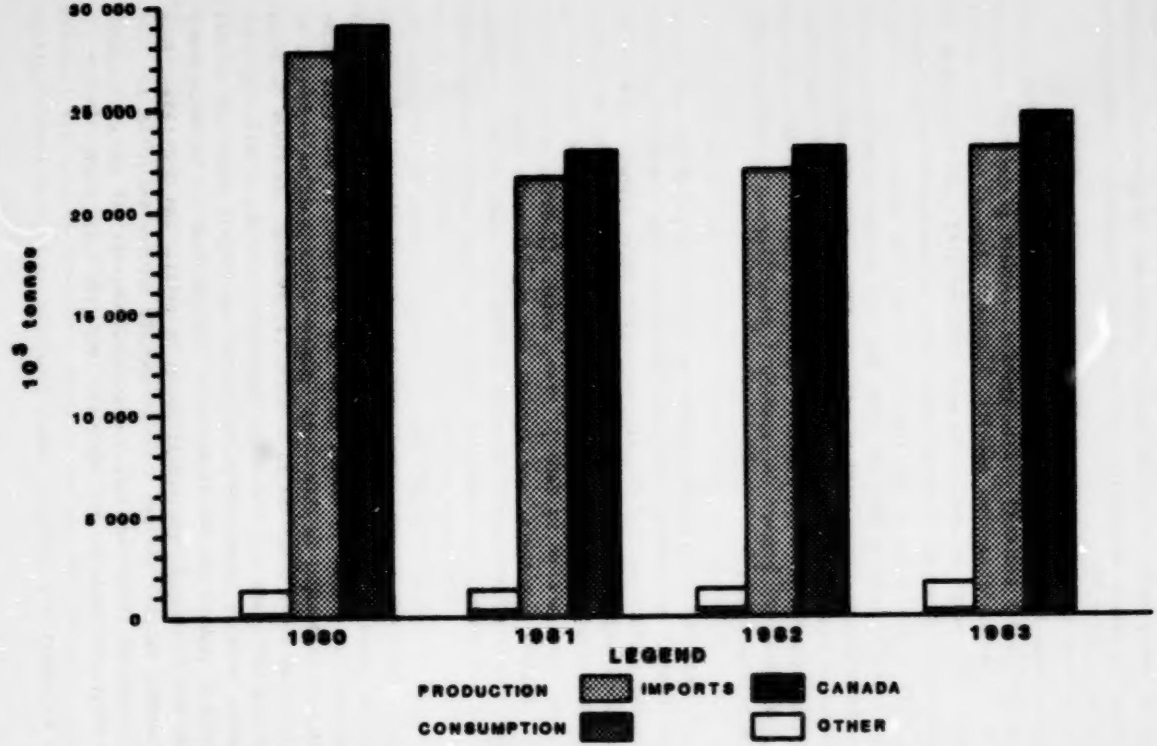
As previously mentioned, these actions could provide new markets for Canadian heavy crude oil, asphalt, and/or bitumen. While the exact amounts that will be needed are indeterminable, the approximate magnitude of asphalt utilization for the duration of the federal program is calculable from data on government expenditures and highway construction material usage factors as follows.

The FHA has calculated that the (weighted) average amount of bitumen (including liquid asphalt materials) used from 1979 to 1981 on interstate highway system construction was 480.7 tonnes per million dollars of total contract construction expenditures. Given this average figure and the fact that the FHA spent $8.68 billion from the HTF in 1981 (see Table D.2), it is estimated that about 4.2 million tonnes of asphalt was used for highway construction in 1981 directly attributable to federal highway funding.[25] Although figures for HTF expenditures in 1983 and FHA estimates of material volumes purchased per unit of government spending are not yet available, 1983 asphalt volumes devoted to federally funded projects are estimated to be about 5.5 million tonnes. Quite clearly, asphalt demand has been significantly affected by the recent government initiatives, and will presumably remain strong at least until the termination of the current program in 1988.[26]

Some 78 percent of U.S. asphalt consumption is used for paving (see Tables D.3 and D.4). Although U.S. asphalt production satisfies most of domestic demand, asphalt imports increased from 4.6 to 6.6 percent of total consumption between 1980 and 1983 (see Figure 5.2 and Table D.5). Canadian imports accounted for 14 percent of total imports in 1983. The portion contributed by Canadian producers increased significantly between 1965 and 1982, but this dropped dramatically both proportionately and in absolute terms in 1983. This is accounted for by PADD V imports from Mexico nearly tripling between 1982 and 1983, imports from the Northern Antilles into PADD I more than doubling, and asphalt from the Netherlands to PADD I also increasing substantially over this period.

All but a negligible amount of asphalt imported by PADD II is from Canada indicating that any increased requirements for this district could come from Canadian sources. While imports from Canada are not as significantly proportional for PADD I, the volume of asphalt imported from Canadian sources is much greater. Increases in spending on road construction in PADD I, then, while affecting several other major asphalt exporters, may account for significantly more Canadian sales than a proportionate increase in PADD II expenditures. (Tables D.3 to D.5 present statistics on asphalt consumption for PADDS I and II.)

While heavy crude oil is the optimal feedstock for the production of asphalt, it is not always used. British Columbia asphalt producers use crudes in blends of 34° to 38°, none of which is heavy crude oil as defined in this study. However, all Canadian exporters of asphalt use heavy crude oil as a feedstock, although sometimes in mixes with lighter crude oil. Although imported crudes are utilized by some Eastern Canadian asphalt refiners, by far the largest potential volumes of export asphalt are associated with refiners that run Canadian heavy crude oils such as Lloydminster, Smiley-Coleville, and Cold Lake. This is evident in that Western Canadian asphalt exports accounted for over 11 percent of total 1983 Canadian exports, whereas all asphalt exports had originated from the East up until 1982 (see Table D.6).



SOURCE: Table D.5.

FIGURE 5.2: U.S. ASPHALT PRODUCTION, CONSUMPTION, AND IMPORTS: 1980-1983

Overall, asphalt produced in Canada from either heavy crude oil or lighter feedstocks is likely to find markets in the U.S. over the next few years. PADD II will be the most probable importer of Canadian asphalt should demand there increase, but PADD I could, because of its size, account for larger volumes if its demand increases.

5.5 The United States Northern Market

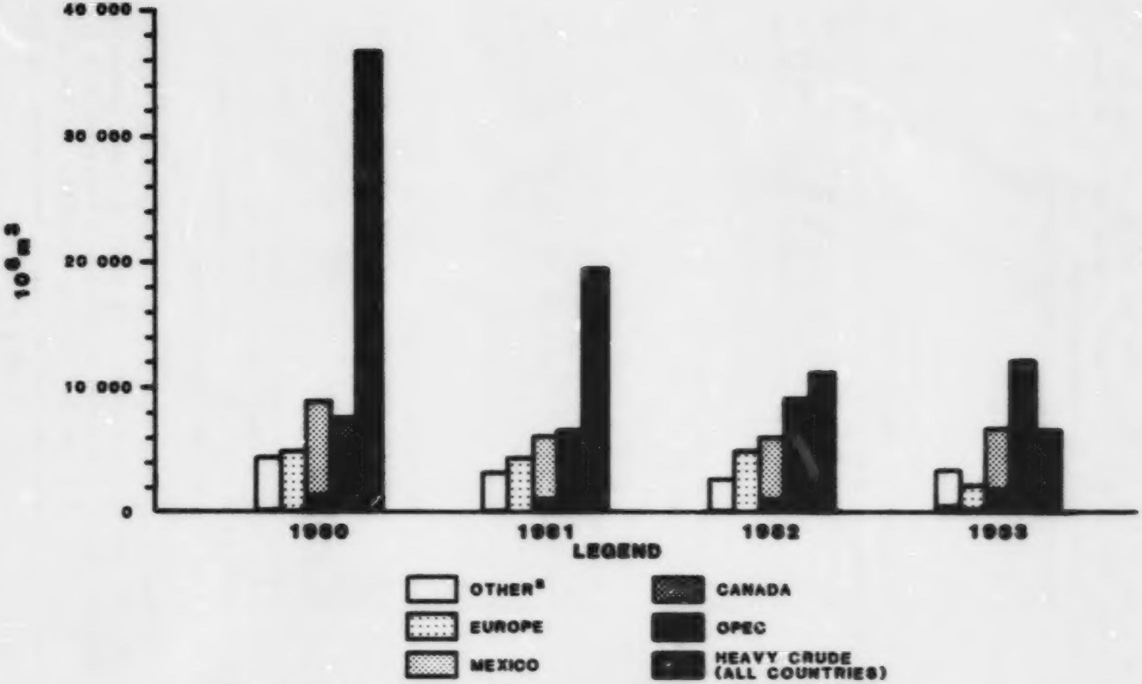
The previous discussion concluded that PADDs I and II are the most likely sources of increased demand for Canadian heavy crude oil both directly and as derived demand through asphalt requirements. The potential for Canadian exports to these regions faces two primary constraints: competition from local and other crude streams, and logistical constraints in terms of transportation facilities and costs. These constraints are discussed below to further specify, to the extent possible, the absolute demand potential of these regions.

5.5.1 Supply and Demand for Crude Oil and Heavy Crude Oil

PADD II domestic production fell during the 1970s due to high foreign and low U.S. crude oil prices. However, price decontrols have recently contributed to steady increases in PADD II crude oil production such that 1983 production was some 28 percent greater than in 1979 (see Table D.7). However, demand has continued to decline with imports and total demand decreasing 65 percent and 31 percent, respectively, over the same time period.[27]

This trend of increasing domestic production with declining imports and demand seems to contradict earlier claims of demand potential for Canadian heavy crude oil in PADD II. However, Canadian exports to PADD II increased almost 60 percent between 1980 and 1983 while Canada's proportion of total PADD II imports increased from 12 to 39 percent (see Figure 5.3 and Table D.8). Moreover, Canadian heavy crude oil exports to PADD II almost doubled over this period while its share of total PADD II heavy crude oil imports increased 9 percentage points to 80 percent in 1983 (see Figure 5.3 and Table D.9).

These results indicate that neither PADD II domestic production, other U.S. domestic production, nor other imported production pose an immediate threat to Canadian heavy crude oil entering PADD II. Interstate crude flow data are not publicly available for the U.S. which limits the conclusions that may be drawn. Nevertheless, on the



SOURCES: Tables D.8 and D.9.

NOTE: [a] Includes Angola, Brazil, Cameroon, Congo, Egypt, Ghana, Guatemala, Netherland Antilles, Oman, Peru, Trinidad and Tobago, Tunisia, and West Africa.

FIGURE 5.3: PADD II CRUDE OIL AND HEAVY CRUDE OIL IMPORTS BY COUNTRY: 1980–1983

basis of past trends, increasing, or at least stable, imports of Canadian crude oil and heavy crude oil by PADD II may be expected.

5.5.2 Logistics[28]

Canadian heavy crude oil is gathered from Western Canadian oil fields and transported to Canadian and U.S. refineries through the Interprovincial Pipe Line (IPL) (see Figure 5.4). The IPL is of fundamental importance to Canadian heavy crude oil exports to the U.S. because it is the only pipeline currently transporting Canadian heavy crude oil to that market. Moreover, the IPL feeds into several northeastern U.S. pipelines which deliver crude oil to refineries in Indiana, Michigan, Minnesota, Ohio, and Pennsylvania.

Concern has been expressed recently about capacity shortages in the IPL, expecially in the case of heavy crude oil which takes twice as long to travel a given distance, and which displaces from two to five times as much light crude oil depending on the relative volume and gravity of the crudes. However, shortage estimates of 16 000 to 27 000 cubic metres per day have been discounted by IPL spokesmen as exaggerated.[29] IPL expects a short-term capacity shortfall of 2250 cubic metres per day on average, primarily between Hardisty, Alberta, and Superior, Wisconsin, but only until the end of 1985 when the upgrading of the third loop between these points is completed.

The $115 million expansion program planned by IPL will add 36 600 cubic metres per day of capacity between Edmonton and Superior and will involve pumping unit expansion, crossover piping, and the switching of heavy and light crude from line 3 to line 2.[30] The greater capacity of line 2, which was previously dedicated to light and medium crudes, will be required to handle the greater than expected volumes of heavy crude oil. In fact, IPL's long-term forecast predicts a maximum export market for Canadian heavy crude oil of about 63 600 cubic metres per day of refinery capacity in the northeastern U.S.

Several other Canadian pipelines could also be used for heavy crude oil exports to the United States. The Trans Mountain pipeline from Edmonton to the Vancouver area has moved some crude oil into the Washington state area and is capable of handling larger volumes given its current low utilisation rate. The Rangeland pipeline currently carries light crude oil and pentanes plus into Edmonton and Montana from Central Alberta. Extensive truck or rail transport, or reversal

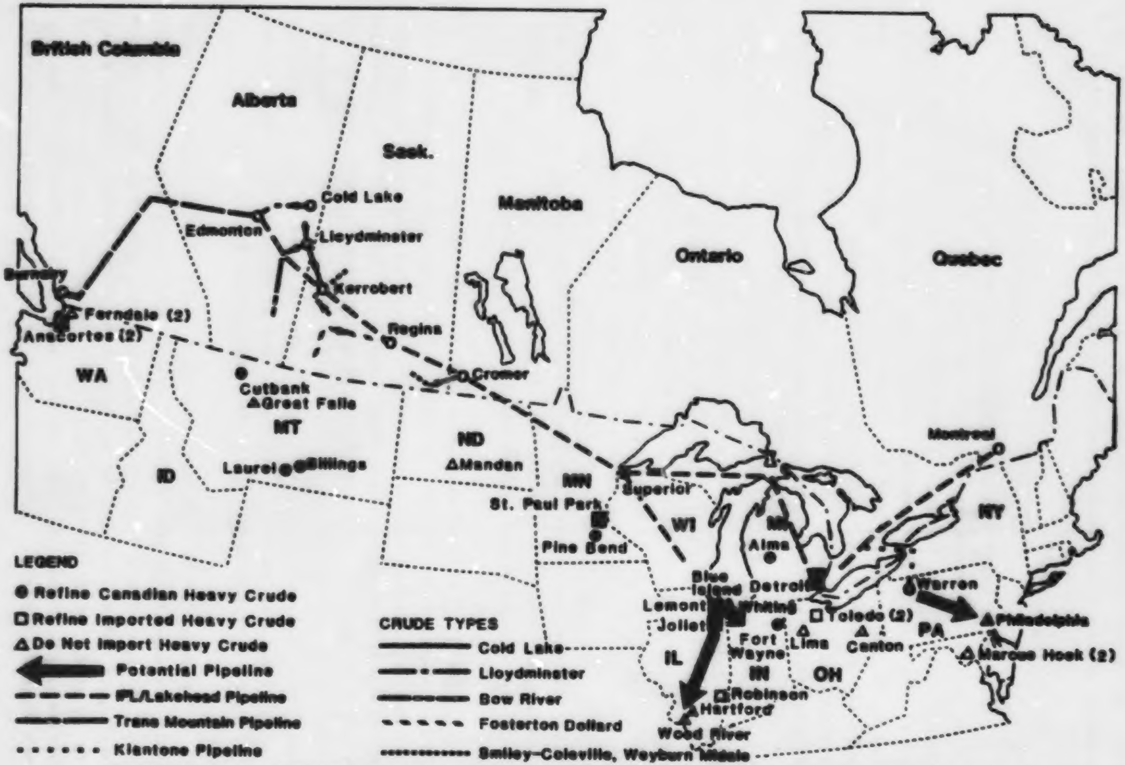

British Columbia
Alberta
Sask.
Manitoba
Ontario
Quebec
Burnaby
Ferndale (2)
Anacortes (2)
Edmonton
Cold Lake
Lloydminster
Kerrobert
Regina
Cromer
Cutbank
Great Falls
Laurel
Billings
Mandan
Superior
St. Paul Park
Pine Bend
Alma
Blue Island
Detroit
Lemont
Whiting
Joliet
Fort Wayne
Lima
Toledo (2)
Canton
Warren
Philadelphia
Marcus Hook (2)
Robinson
Hartford
Wood River
Montreal
WA
ID
MT
ND
MN
WI
MI
IL
IN
OH
PA
NY
LEGEND
Refine Canadian Heavy Crude
Refine Imported Heavy Crude
Do Not Import Heavy Crude
Potential Pipeline
IPL/Lakehead Pipeline
Trans Mountain Pipeline
Kiantone Pipeline
CRUDE TYPES
Cold Lake
Lloydminster
Bow River
Fosterton Dollard
Smiley–Coleville, Weyburn Midale

FIGURE 5.4: EXISTING AND POTENTIAL PIPELINES CARRYING CANADIAN HEAVY CRUDE OIL, AND U.S. REFINERS OF CANADIAN HEAVY CRUDE OIL

of the northern pipeline link to Edmonton would be required to transport Canadian heavy crude oil through this line. Finally, the Wascana pipeline extends from Regina to the U.S. border in Montana where it connects with the Wesco/Butte pipeline system. The line is not currently operating and could be used for Canadian heavy crude oil exports to the U.S.

In addition to these lines, adjustments or extensions to other lines could also open new U.S. markets to Canadian heavy crude oil. The Montreal/Portland triple pipeline currently moves limited amounts of imported crude oil from Portland, Maine to Montreal refineries. If one of these lines was reversed, Canadian crude oil could then be moved by tanker from Portland to U.S. refineries on the East Coast.

Wood River is a major refining centre in PADD II currently supplied by U.S. domestic production and foreign crudes from the Gulf Coast through pipelines flowing north. Canadian crude oil could augment and/or displace these supplies through several routes, all of which would require reversal of one pipeline ultimately tied to IPL. However, the expense involved could be justified in that most of PADDs II and III would be accessible to Canadian crude oil from Wood River making it key to market expansion for Canadian heavy crude oil exports.

The feasibility of all of these possibilities depends on the costs involved for additional transportation. Nevertheless, the physical viability requires only sufficient supply/demand balances and crude oil price differentials to make these schemes economic. From the previous analysis, future demand could warrant any one of these logistical changes. However, a primary constraint remains in the diluent requirement for transporting heavy crude oil. Chapter 6 to follow will examine this issue and its potential effect on Canadian heavy crude oil exports to the United States.

5.6 Market Interface for Canadian Heavy Crude Oil

The "market interface" for a commodity is the (usually spatial) location in which that commodity meets with its nearest competitor or substitute. In the case of crude oil, the market interface is determined by the cost of production plus the cost of transportation. Accordingly, Canadian heavy crude oil will penetrate Canadian and U.S. markets to the extent that the total cost of production and transportation is less than or equal to that of its nearest competitor.

In the short term, only those refineries accessible by existing pipeline systems are considered part of the market interface. The volume of Canadian heavy crude oil accepted by these refineries could be increased in several ways. First, the share of Canadian to total heavy crude oil intake by refineries could be increased. Given the relatively low sulphur and heavy metals content of Canadian heavy crude oil, this option could be possible provided that transportation and tariff costs do not make it uneconomic. By the same token, a larger share of heavy to total crude oil could be accepted provided limitations in terms of refinery capacity do not preclude this. Finally, the recent increases in refined products demand could increase the overall demand for crude oil, including Canadian heavy crude oil, subject to transportation costs and refinery configuration constraints.

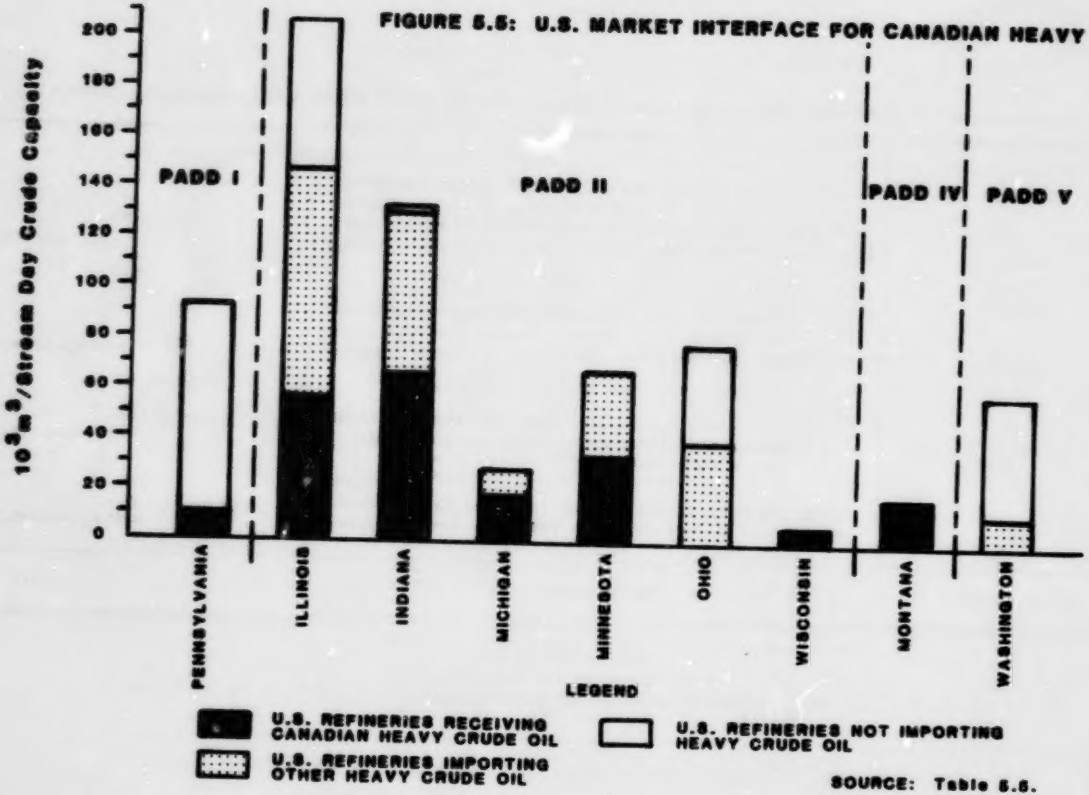
In the long term, any of the logistical changes discussed earlier could extend the interface considerably. Moreover, in the long term, refinery configurations may also be adapted or expanded to increase heavy crude oil capacity. As already noted, this has been the trend for several years due to the relatively heavier crude oil slate available. Tables 5.3 and 5.4 outline current and proposed heavy crude oil refining capacity projects in both Canada and the U.S., and indicate that this trend is still prevalent.

Three general categories of refineries may be identified for both the short-term and long-term market interface. In order of greatest likelihood for receiving Canadian heavy crude oil, these are:

- refineries currently accepting Canadian heavy crude oil,
- refineries receiving other imported heavy crude oil, and
- refineries not importing heavy crude oil.

Figures 5.4 and 5.5, and Table 5.5 present the geographic location and crude capacity of the refineries that comprise the U.S. market interface for Canadian heavy crude oil. The list was derived from analysis of refineries historically receiving Canadian and imported heavy crude oil, and from a survey of U.S. refineries conducted by CERI in September of 1984 that identified refineries that

FIGURE 5.5: U.S. MARKET INTERFACE FOR CANADIAN HEAVY CRUDE OIL



SOURCE: Table 5.5.

TABLE 5.3

PLANNED CANADIAN REFINERY HEAVY CRUDE OIL CAPACITY PROJECTS AS OF APRIL 1984

Company	Proposed Change	Completion Date
Chevron Canada Ltd.	Upgrade crude unit and fluid catalytic cracker to reduce heavy fuel oil production at Burnaby, B.C. refinery	1984
Petro-Canada	Installation of 800 m^3/d Canmet hydrocracker at Montreal East refinery	1985
Petro-Canada	Replace existing fluid cat cracking unit with a 3200 m^3/d cat cracker using Total resid cat cracking process at Montreal East refinery	1986
Suncor Inc.	Upgrade Sarnia refinery including installation of a hydrocracker, vacuum unit, hydrogen plant, and sulphur recovery unit designed to virtually eliminate heavy fuel oil production	1984

SOURCE: "Refinery and Petrochemical Report," Oilweek, April 16, 1984, pp. 11-13.

TABLE 5.4

PLANNED U.S. REFINERY HEAVY CRUDE OIL CAPACITY PROJECTS AS OF OCTOBER 1984

Company	Proposed Change	Completion Date
American Petrofina	795 m^3/d hydrotreater at Port Arthur, Texas refinery	1985
Amoco Oil	9539 m^3/d hydrocracker for resid upgrading; and Ultracracker at Texac City, Texas refinery	1984 1985
Conoco	1828 m^3/d hydrotreater at Lake Charles, Calif. refinery; and 1590 m^3/d hydrotreater at Ponca City, Okla. refinery	1985 1986
Exxon USA	3975 m^3/d Flexicoker for resid upgrading at Baytown, Texas	1987
GHR Energy Corp.	7154 m^3/d coker at Good Hope, La. refinery	1985
Koch Refining	6359 m^3/d FCC units revamped and 1908 m^3/d delay coker installed at Corpus Christi, Texas refinery; and 3180 m^3/d hydrotreater to produce gas oil at Rosemount (Pine Bend), Ill. refinery	1985 1985
Phillips Petroleum	668 m^3/d FCC Unit at Sweeny, Texas refinery	1985
Provident Energy Cl.	1749 m^3/d delay coker; 4038 m^3/d hydrocracker; 1622 m^3/d hydrotreater; and 1590 m^3/d asphalt operation to process vac bottoms at Mobile, Ariz.	1987
Tenneco	3100 m^3/d FCC unit; and 2862 m^3/d delay coker with total capacity of 4293 m^3/d at Chalmette, La. refinery	1985
Texaco	Modern FCC at El Paso, Texas refinery	1985
Union Oil of Ca.	415 m^3/d delay coker at Lemont, Ill. refinery; and 1590 m^3/d delay coker at Rodeo, Calif. refinery	1985 1985

SOURCE: "Worldwide Construction Report," Oil and Gas Journal, October 29, 1984, pp. 87-88.

are able to run heavy crude oil but either are not currently doing so, or are using either domestic heavy crude oil or heavy crude oil imported by another refinery.

This latter point requires a note of caution. Several refiners that do not appear in the American Petroleum Institute database as recipients of imported heavy crude oil claimed to run imported heavy crude when responding to the survey conducted by CERI. On the other hand, one refiner that responded negatively to the survey regarding whether they run heavy crude oil appears in the database as a recipient of imported heavy crude. These anomalies are likely attributable to crude oil transfers between refineries. Nevertheless, such factors preclude positive identification of refiners that process only domestic or foreign heavy crude oil.

A final qualification is that several of the refineries listed in Table 5.5 appear in more than one column as they import both Canadian and other foreign heavy crude oil. For this reason the capacity totals of the three categories are not additive. Nevertheless, the overall capacity is provided, and the totals of the three groups appear below and in Figure 5.5 as illustrative figures.

The first category represents the existing market interface. Increased Canadian heavy crude oil flows to these refineries would require cost reductions to displace other crudes being received and/or increased heavy crude oil capacity at these refineries. These refineries are primarily located in PADD II and represent total capacity of some 208 000 cubic metres per stream day.

Refiners currently running other imported heavy crude oils are the next most proximate buyers and are generally located in Illinois and Ohio (PADD II). Since many of these refiners already receive some Canadian heavy crude oil, a lower price for Canadian heavy crude may increase its utilization by these refiners. However, capacity constraints may also prevail. Moreover, in the case of the Marathon refinery in Robinson, Illinois, an additional pipeline link or trucking would be required. The viability of such a scheme depends on the delivered cost of Canadian heavy crude oil and the amount of imported heavy crude oil that could be displaced. In total, these refineries account for 251 000 cubic metres per stream day of capacity with 95 percent of that total located in PADD II.

TABLE 5.5

U.S. MARKET INTERFACE FOR CANADIAN HEAVY CRUDE OIL

Refiner/Location	Refinery Capacity (10^3m^3/sd)	U.S. Refiners Receiving Canadian Heavy Crude	U.S. Refineries Importing Other Heavy Crude	U.S. Refineries Not Importing Heavy Crude[a]
PADD I				
BP/Marcus Hook Penn.	28	-	-	1
Gulf/Philadelphia, Penn.	29	-	-	1
Sun/Marcus Hook, Penn.	26	-	-	1
United/Warren, Penn.	10	1	-	-
Total	93	1	-	3
PADD II				
Amoco/Mandan, N.D.	9	-	-	1
Amoco/Whiting, Ind.	64	1	1	-
Ashland/Canton, Ohio	11	-	-	1
Ashland/St. Paul Park, Minn.	11	1	1	-
Clark/Blue Island, Ill.	10	-	-	1
Clark/Hartford, Ill.	8	-	-	1
Gladieux/Ft. Wayne, Ind.	3	1	-	-
Koch/Pine Bend, Minn.	23	1	1	-
Laketon/Laketon, Ind.	2	-	-	1
Marathon/Detroit, Mich.	11	1	1	-
Marathon/Robinson, Ill.	33	-	1	-
Mobil/Joliet, Ill.	32	1	1	-
Murphy/Superior, Wis.	6	1	-	-
Shell/Wood River, Ill.	41	-	-	1
Sohio/Lima, Ohio	28	-	-	1
Sohio/Toledo, Ohio	20	-	1	-
Sun/Toledo, Ohio	20	-	1	-
Total/Alma, Mich.	7	1	-	-
Union/Lemont, Ill.	25	1	1	-
Total	364	9	9	7

Continued on Next Page

TABLE 5.5 (Continued)

Refiner/Location	Refinery Capacity ($10^3 m^3$/sd)	U.S. Refiners Receiving Canadian Heavy Crude	U.S. Refineries Importing Other Heavy Crude	U.S. Refineries Not Importing Heavy Crude[a]
PADD IV				
Cenex/Laurel, Mont.	7	1	-	-
Conoco/Billings, Mont.	8	1	-	-
Flying J./Cutbank, Mont.	1	1	-	-
Simmons/Great Falls, Mont.	1	-	-	1
Total	17	3	-	1
PADD V				
Arco/Ferndale, Wash.	23	-	-	1
Mobil/Ferndale, Wash.	12	-	-	1
Shell/Anacortes, Wash.	12	-	1	-
Texaco/Anacortes, Wash.	13	-	-	1
Total	60	-	1	3
TOTAL	534	13	10	14

SOURCES: (1) American Petroleum Institute, Imported Crude Oil and Petroleum Products Reports (Database); (2) CERI Survey, September 1984; and (3) Oil and Gas Journal, March 26, 1984, pp. 112-123.

[a] Includes refineries capable of, but not currently, running heavy crude oil and refineries using domestic heavy crude oil.

The third category includes refineries capable of, but not currently, running heavy crude oil and refiners receiving U.S. domestic heavy crude oil. These are primarily located in Washington (PADD V), Pennsylvania (PADD I), and Illinois and Ohio (PADD II). The Washington refiners could be supplied through the Trans Mountain pipeline system as previously discussed. Access to the Pennsylvanian refiners would require a short additional pipeline link. Nevertheless, the price differential between Canadian and other crudes imported into this area is not so large as to preclude the construction of such an extension. The Patoka/Wood River area in Illinois is a major U.S. refining centre that could be accessed by pipeline extension or reversal. This area is potentially very significant for Canadian heavy crude oil exports because the Marathon refinery at Robinson alone imported over half a million cubic metres of foreign heavy crude oil in 1983. Again, accessing this area would depend on the relative delivered costs of Canadian and imported and/or domestic crude oils. Since refinery configuration is not an obstacle, changes in crude oil price differentials and/or refined products demand could be necessary to open this market to Canadian heavy crude oil. The refineries have total capacity of 241 000 cubic metres per stream day.

The total capacity of the refineries comprising the U.S. market interface for Canadian heavy crude is 534 000 cubic metres per stream day. Canadian crude oil imports to this same set of refineries amounted to only 43 000 cubic metres per day in 1983, 33 000 cubic metres per day of which was heavy crude oil. Although the proportion of Canadian heavy crude oil imports to total capacity amounts to only 6 percent, the remaining 94 percent cannot be assumed to be market potential. Other heavy crude oil imports to these refineries of almost 8000 cubic metres per day represent potential for displacement subject to refinery configuration and accessibility to Canadian heavy crude oil streams. As previously indicated, receipts of domestic heavy crude oil by these refiners are not identifiable with publicly available data, but survey and historical data do indicate some market potential in this area as well. Finally, the relatively low percentage of total capacity of the U.S. market interface serviced by Canadian heavy crude oil could indicate some room for expansion simply by accepting larger volumes of heavy crude oil. Again, configuration and logistical constraints apply.

5.7 Summary and Conclusions

On the basis of the above analysis, some potential exists for sales of Canadian heavy crude oil into the United States market. As the supply of domestic crude oil diminishes over time, the United States will import larger quantities of crude oil. As world crude oil reserves are depleted, the API gravity of imported crudes will fall. Thus, refinery runs will of necessity include increasingly large proportions of heavier crude feedstocks. Canada's share of U.S. crude oil imports will depend on comparative export prices and transportation tariffs; that is, the relative cost to the purchaser of imported crudes.

Two additional factors affect potential sales of Canadian heavy crude oil in the U.S. First, decontrolled crude oil prices and increased incentives to expand and upgrade heavy crude oil refining capacity have opened the door for increased Canadian crude oil exports to the U.S. Second, the U.S. government's initiatives to upgrade its highway system could increase demand for Canadian heavy crude oil since it is generally used as a feedstock for asphalt. Thus, demand for asphalt in the U.S. could represent a derived demand for Canadian heavy crude oil. This factor will be particularly significant in northern U.S. states that traditionally import Canadian asphalt.

Examination of the existing and potential market interface for Canadian heavy crude oil reveals both short- and long-term potential for increased exports to the U.S., subject to price and transportation constraints. While the current supply/demand/price environment seems favourable, and pipeline facilities are not an immediate problem, one final constraint remains: the availability of diluent to facilitate transport of viscous Canadian heavy crude oil. This issue is addressed in the following chapter.

Footnotes

[1] For example, Hycarb Engineering Ltd., *Canadian Heavy Crude Oil Market Analysis* (Calgary: Hycarb Engineering, 1984), and U.S. Department of Energy, *Energy Projections to the Year 2010* (Washington, D.C.: Office of Policy, Planning and Analysis, 1983).

[2] United States, Department of Commerce, Office of Competitive Assessment, *U.S. Energy for the Rest of the Century - 1983* (DOC/OEA/OCA/5) (Washington, D.C.: National Technical Information Service, July 1983), p. iii.

[3] Ibid., pp. 11-12.

[4] U.S. Department of Energy, Office of Policy, Planning and Analysis, *Energy Projections to the Year 2010*, p. iii.

[5] Commentary and information on the U.S. regulatory environment prior to 1981 is derived from Doan L. Phung and Richard N. Barnes, *The Petroleum Refining Industry in the 1980's: Impact of the National Energy Plan and Related Legislation* (Oak Ridge, Tennessee: Institute for Energy Analysis, Oak Ridge Associated Universities, 1981). By banning foreign carriers from transporting crude between U.S. locations, the Merchant Marine Act caused the establishment of the Caribbean refining industry.

[6] For example, The Energy and Petroleum Allocation Act, The Energy Policy and Conservation Act, and the Entitlement Program.

[7] Views and proposals from all sectors of the economy are to be solicited and incorporated into the President's report. The National Energy Act (NEA) was a direct result of the first NEP, which still provides its general policy framework.

[8] U.S. Department of Energy, Office of Public Affairs, *The National Energy Act* (Washington, D.C.: U.S. Government Publications Office, November 1978).

[9] U.S. Department of Energy, *National Energy Plan II* (Washington, D.C.: U.S. Government Publications Office, May 1979), p. 73. NEPP 1979 recognized that oil and natural gas should be priced at their "replacement cost" in order to encourage domestic conventional production. Accordingly, a price decontrol schedule was fixed whereby June 1, 1979 would see newly discovered oil receiving world price and 80 percent of production from marginal wells obtaining the current "upper tier" price. Six months later, the remaining 25 percent of marginal well production would be sold at upper tier prices, while the upper tier price itself would begin to move in monthly increments toward the world price. Moreover, oil volumes classified as "lower tier" were allowed to decline at a rate of 3 percent per month.

[10] Analysis of the effects of this and other aspects of NEPP II is available in U.S. Department of Energy, Assistant Secretary for Policy and Evaluation, National Energy Plan II, Appendix C: Energy and the Economy (DOE/TIC-10203 [App. C]) (Washington, D.C.: National Technical Information Services, May 1979).

[11] Ibid., p. 86.

[12] U.S. Department of Energy, Securing America's Energy Future: The National Energy Policy Plan (DOE/S-0008) (Washington, D.C.: U.S. Government Publications Office, July 1981), p. 1.

[13] Natural gas remained subject to price controls such that, under current market conditions, gas prices are widely believed to be artificially high. Natural gas consumption accounts for 26 percent of total U.S. energy use: some 17.7 trillion cubic feet in 1982 of which 5 percent is imported. The Natural Gas Policy Act Amendments bill which decontrols prices and limits "take or pay" contracts was recently passed by the U.S. Senate.

[14] U.S. Department of Energy, The National Energy Policy Plan (DOE/S-001) (Washington, D.C.: United States Government Publications Office, October 1983).

[15] Ibid., p. 22.

[16] Leo R. Aalund, "Refinery Capacity Dips on Broad Front," Oil and Gas Journal, Volume 81, No. 12 (March 21, 1983), pp. 83-85.

[17] Leo R. Aalund, "U.S., Canadian Refiners Still Retrenching," Oil and Gas Journal, Volume 82, No. 13 (March 26, 1984), pp. 71-83.

[18] Ibid., p. 73.

[19] New York Times, November 27, 1983, p. XXIII-1. See Table D.2 for figures for 1981 and 1982.

[20] Funds made available under the Act were not freed by Congress until March 1984. New York Times, March 1984, p. IV-26.

[21] New York Times, January 2, 1983, p. I-20. The gasoline tax went into effect April 1983.

[22] Accordingly, states that will receive the largest proportional increases in funding are Indiana, Michigan, Mississippi, Missouri, North Carolina, Ohio, Oklahoma, and Texas.

[23] New York Times, January 16, 1984, p. II-7.

[24] The New Jersey state administration proposed a $3.3 billion program in February 1984 (*New York Times*, February 12, 1984, p. XI-4). Pennsylvania has budgeted $88 million more for road and bridge repairs in fiscal year 1983-1984 than in 1982-1983 (*New York Times*, February 13, 1983, p. I-37). Connecticut plans a 10-year, $5 billion highway and transportation system improvement program to be funded by higher gasoline taxes and licence fees (*New York Times*, February 1, 1984, p. II-2).

[25] U.S. Department of Transportation, Federal Highway Administration, *Highway Construction Usage Factors for Cement, Bitumens, Concrete Pipe and Clay Pipe* (Washington, D.C.: 1979, 1980, and 1981); and U.S. Department of Commerce, Bureau of the Census, *Federal Expenditures by State* (Washington, D.C.: 1982 and 1983).

[26] Technological change, even in this brief period, could dramatically affect asphalt demand. For example, a new method of pre-stressing concrete roadbeds has been shown to significantly reduce deterioration of the road surface. The method is considerably cheaper than currently practised, leading to the speculation that savings in construction could be transferred to upgrading, repairing, and resurfacing older portions of the system built with the traditional technique. Hence, asphalt demand could actually increase, since less money is expended on concrete with the pre-stressing method (*New York Times*, July 4, 1983, p. 27).

[27] Demand for crude oil in PADD II is estimated by adding imports to domestic production. Ideally, changes in both inventories and exports should be accounted for in estimating demand, but data on these quantities are not available. It is assumed, therefore, that such considerations would not significantly alter overall trends or magnitudes in the supply/demand balance.

[28] Appendix D outlines various Canadian pipelines and the crude streams they carry in more detail. The appendix discussion is based on similar analysis in Hycarb Engineering Ltd., *Canadian Heavy Crude Oil Market Analysis*, pp. 231-265.

[29] The problem originated with a 12 percent increase in conventional crude oil production allowed by the Alberta ERCB when a fire in Syncrude Canada's Fort McMurray oil sands plant decreased synthetic crude supply by 17 500 cubic metres per day. When Syncrude resumed production in October, the IPL system was already operating at capacity. Syncrude's second coker was expected to be operational again by December contributing an additional 9500 cubic metres per day of crude. See "Pipeline "Crisis" Comes As No Surprise," *Energy Analects*, Volume 13, No. 46 (November 23, 1984), p. 1.

[30] "IPL Plans Major Expansion Program," *Oilweek*, December 17, 1984, p. 2.

Chapter 6

DILUENT SUPPLY/DEMAND ANALYSIS AND FORECAST

6.1 Introduction

The marketing of Canadian heavy crude oil is hindered by its inaccessibility to markets. Since the low API gravity of heavy crude oil may preclude pipelining of heavy crude below 20° API in its natural state, and complicates the pipelining of heavy crude between 20° and 29° API, the issue becomes how to alter the crude such that it may be transported economically. For example, the minimum API gravity accepted by the Interprovincial/Lakehead pipeline system is 20° to 22° API. Premiums of 15 percent and 5 percent over light crude oil tariffs are charged for heavy crude oils with gravities of less than 25° API, and between 25° to 30° API, respectively.

The API gravity of heavy crude oil may be raised in several ways. The most common method currently used is dilution by a lighter hydrocarbon, typically pentanes plus. Alternative diluents include light crude oils, synthetic crude oils, and naphthas. Several alternatives to diluents which may be used to the same end include hot oil pipelining and upgrading.

All of these possible methods of increasing the API gravity of heavy crude oil are subject to supply, demand, and cost constraints which may limit their usefulness to producers of Canadian heavy crude oil. If no method is economic, the development of Canada's heavy crude oil resources will be hindered. In particular, since pentanes plus, the diluent most commonly used in Canadian practice, is forecast to be in short supply in the near future, this chapter examines the supply/demand situation for condensate diluent.[1] Future trends, condensate pricing, and alternatives are also discussed.

6.2 Canadian Pentanes Plus Supply/Demand Analysis

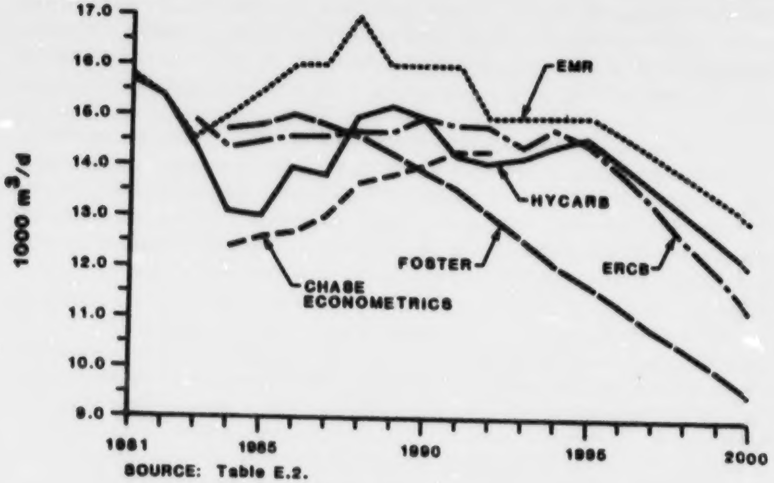
6.2.1 Supply

The very nature of condensate--a naturally occurring hydrocarbon--sets an ultimate limit on its supply potential. Additional limitations include low pentanes plus-to-gas recovery ratios and the accessibility of supply. In fact, Canadian production of pentanes plus fell over 45 percent between 1973 and 1982, and reserves fell 9 percent from 1978 to 1983, basically due to lower recovery rates from natural gas production (see Table E.1). The ultimate condensate potential in Alberta has been estimated by the Alberta Energy Resources Conservation Board (ERCB) at about 320 million cubic metres, approximately 59 years of supply at 1983 production levels.[2]

Potential supply is further diminished by volumes that cannot be recovered economically. For example, condensate used in miscible flooding generally cannot be economically recovered and transported to markets. Similarly, some condensate is transported with crude oil from the field since separation is uneconomic. The Rangelands pipeline system from the Waterton refinery carries condensate with crude oil exports because no line is available to carry the condensate to Canadian markets. Finally, significant quantities of condensate are transported as part of a natural gas liquids stream to Eastern Canada where it is used as petrochemical feedstock or sold to other refineries.[3] These streams, which are currently unavailable for other uses, including diluent use, have been estimated at some 40 percent of total production in 1984.[4]

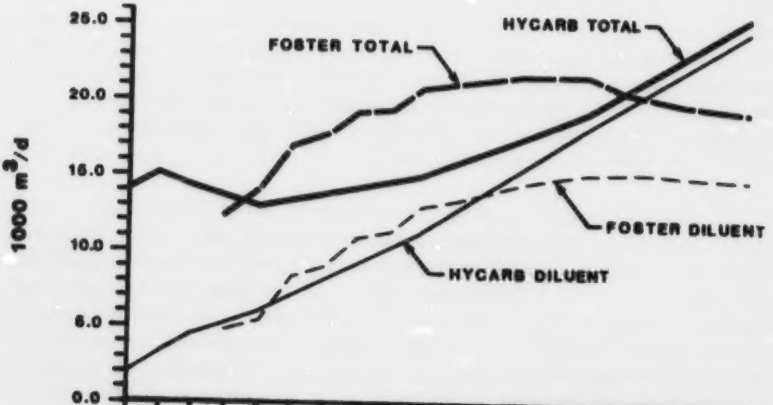
As a result of the aforementioned constraints, the supply of pentanes plus is expected to decrease over time. The primary cause through the short term (to 1990) is a diminishing rate of recovery of condensate from associated natural gas production. Several large cycling condensate pools have largely accounted for Alberta's condensate production to date. Cycling or recycling operations are used to maintain reservoir pressure and prevent formation of retrograde condensate. Moreover, gas has also been used in some oil fields to maintain pressure. As the oil pools currently on recycle enter the blowdown phase, recycle ends and reservoir production declines rapidly, simultaneously decreasing condensate production.[5] Also, as the lighter, more accessible oil pools are depleted, the proportion of condensate available is diminished, further decreasing supply.

Various pentanes plus supply forecasts to the year 2000 are depicted in Figure 6.1.[6] While some forecasts follow each other quite closely (i.e., the Energy Mines and Resources Canada (EMR), the Alberta Energy Resources Conservation Board (ERCB) and the Hycarb Engineering forecasts), a very broad range is shown (see also Table E.2). For example, the Foster Research forecast is initially close to



SOURCE: Table E.2.

FIGURE 6.1: FORECAST CANADIAN PENTANES PLUS SUPPLY: 1981-2000



SOURCE: Table E.3.

FIGURE 6.2: FORECAST CANADIAN PENTANES PLUS DEMAND: 1981-2000

the others, but is some 20 percent lower than the Hycarb forecast after 1995. Overall, these two forecasts yield a 2.8 and 0.5 percent annual decrease, respectively, from 1985 to 2000. On average, Canadian pentanes plus supply is forecast to decrease by 1.3 percent annually over the same period.

Despite the aforementioned differences, the forecasts generally indicate a moderate increase in short-term pentanes plus supply, with more severe declines after about 1990. These results are consistent with the earlier discussion and are due to market response to improved gas export markets initially increasing supply and then ultimate supply limitations associated with declining oil production.[7]

6.2.2 Demand

Canadian refineries require varying amounts of pentanes plus for use in processing light end products and fuels. This demand, however, is seasonal, peaking in the summer months, and is not essential to plant operations since substitutes may be used. The exception to this rule is the Shell Bowden refinery which operates solely on pentanes plus.

As the available supply of pentanes plus decreases in the future, less will be available for such seasonal demands. New refineries such as Shell's Scotford refinery in the Edmonton area and refineries currently in construction and planning stages will likely not be based on condensate as feedstock. Moreover, there are indications that pentanes plus demand by the Bowden refinery will be reduced. This should make more condensate available for diluent use.

Diluent demand is directly related to heavy crude oil production. Therefore, the projected increases in heavy crude oil supply and demand (see Chapter 4) will simultaneously increase demand for pentanes plus as diluent. Different proportions of diluent are required for different types of heavy crude oil and bitumen.[8] In the aggregate, diluent demand is forecast to represent an increasing percentage of total pentanes plus demand (see Figure 6.2 and Table E.3). On average, diluent demand is forecast to increase at an average annual rate of 8.7 percent from 1985 to 2000 while total demand increases at only 3.5 percent annually over the same period.

The significant differences in the projections are due to two primary factors. First, while the Foster Research study defines unavailable supply based on currently unavailable sources at about 42 percent of total supply throughout the forecast period, the Hycarb Engineering study assumes that much of the unavailable supply will be released for other uses after 1990 (i.e., quantities demanded by other users for whom no alternatives previously existed will no longer be required due to changes in technology or physical handling capability). However, the high cost associated with making these streams available makes this latter assumption unlikely. Second, Foster's forecast of diluent demand levels off after 1995, while Hycarb projects increasing diluent demand right to 2000, primarily due to high levels of bitumen production. As a result, the Foster data indicate a 7 percent average annual increase in diluent demand from 1985 to 2000 compared with the 10 percent average annual increase expected by Hycarb over the same period. CERI expects gradual increase to the end of the century, although the extent of the increase is difficult to determine accurately.

6.2.3 Supply/Demand Balance

The Alberta market for pentanes plus has been basically regulated since 1982 when responsibility for distribution of pentanes plus production from Crown lands (some 80 percent of total production) was given to the Alberta Petroleum Marketing Commission (APMC). Thus, while supply and demand are primary considerations in the decision-making process, free-market forces are somewhat constrained, primarily by an unpublished "priority list" that is followed in allocating available supply.

Because of an agreement with the provincial government, the Shell Bowden refinery is guaranteed adequate supply. The pentanes plus exported to the U.S. through the Rangelands pipeline system also ranks as top priority, simply because the economics to date have precluded recovery for use in Canada. Diluent demand for blending with Alberta and Saskatchewan heavy crude oils ranks third and fourth, respectively, followed by demand by Alberta refineries, and other Canadian refineries and petrochemical plants.

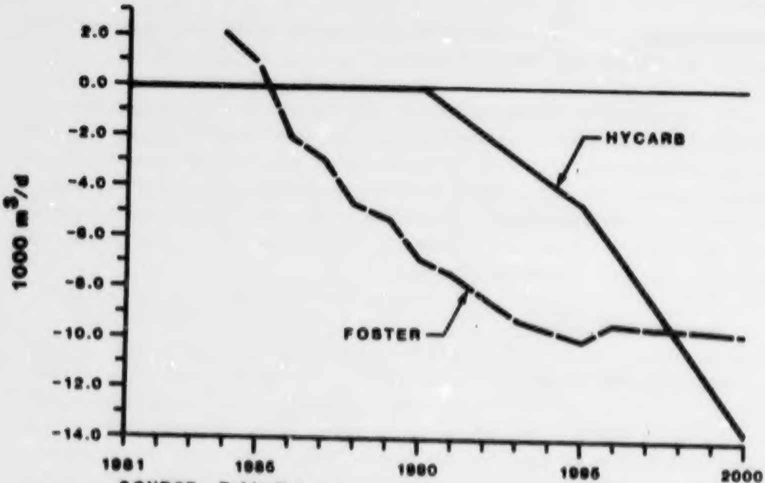
Alberta refinery demand was formerly placed before Saskatchewan heavy crude oil diluent requirements on the priority list. The order was reversed as of January 1, 1983 due to the seasonal demand of the refineries and the fact that they could substitute other light crude oils for pentanes plus.

Although Saskatchewan heavy crude oil diluent requirements were sometimes not met in 1981 and 1982 because of the order of priorities at that time, it is not readily apparent that much market distortion occurred. The APMC ranking is seemingly based on the greatest need (in terms of requirement rather than amount), which would also occur under free market conditions. However, under free market conditions, a different price would likely be paid by each user. This will be discussed in Section 6.3 under Condensate Pricing.

The range of supply/demand balance forecasts, given the current market situation, is depicted in Figure 6.3 (see also Table E.4). Supply shortfalls are indicated as early as 1986 and are projected to increase rapidly thereafter. The differences in the two forecasts are due to varying assumptions regarding future bitumen production. The Foster study discounts proposed bitumen projects after 1995 as being too tenuous to include, while Hycarb expects steadily increasing bitumen production to the end of the period. The different forecasts of bitumen production significantly impact diluent demand since as much as 50 percent diluent is required to transport a given volume of bitumen. The extent of the impact is seen in that, had Hycarb maintained bitumen production at 1990 levels to the year 2000, virtually no diluent shortage would be forecast. Alternatively, had Hycarb made the same assumption as Foster (i.e., that no new bitumen projects come on stream after 1995), the forecast diluent shortage for 2000 would be halved. On average, the supply shortfall increases substantially between 1985 and 2000, from an average surplus of 600 cubic metres per day in 1985 to an average shortfall of 11 100 cubic metres per day in 2000.

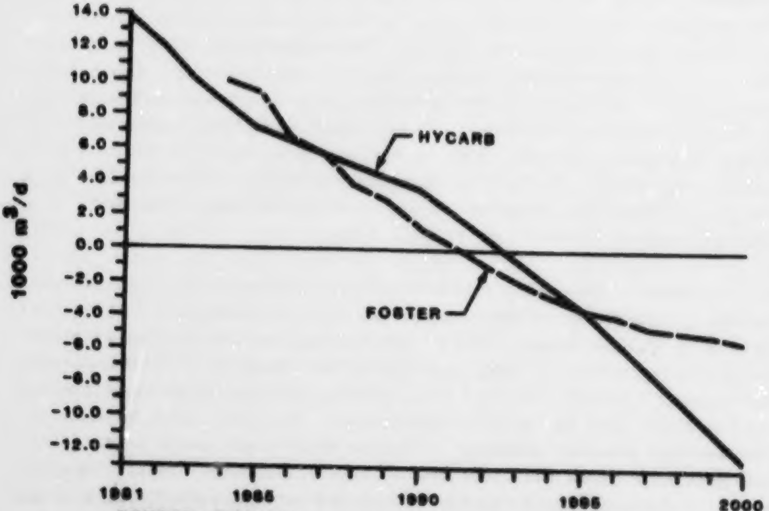
The seriousness of the supply shortfall becomes increasingly evident when total projected supply is compared with diluent demand alone. Figure 6.4 indicates supply shortfalls by about 1992, based on diluent demand alone (see also Table E.4).

Time and resources did not allow for development of a CERI forecast based on raw data. However, analysis of available studies plus discussion with industry and government contacts indicate that some shortage of diluent will occur by the mid-1990s, corroborating the forecasts in Figures 6.3 and 6.4. The extent of this shortage cannot



SOURCE: Table E.3.

FIGURE 6.3: FORECAST CANADIAN PENTANES PLUS S/D BALANCE: 1981-2000 (SUPPLY LESS DEMAND)



SOURCE: Table E.4.

FIGURE 6.4: FORECAST CANADIAN DILUENT S/D BALANCE: 1981-2000 (SUPPLY LESS DEMAND)

be determined, but it is expected to be relatively low, and probably not as severe as some have indicated.

The limited supply potential and increasing demand requirements for pentanes plus indicate the building of considerable pressure on the condensate market. As this pressure increases, the regulation of the market by the APMC will likely have an increasing significance, particularly in terms of pricing distortion. The likely effects on condensate and heavy crude oil pricing with and without regulation are discussed in the following section.

6.3 Condensate Pricing

6.3.1 Canadian Pricing

The Alberta Petroleum Marketing Commission regulates the distribution and pricing of the bulk (some 80 percent) of condensate production in Alberta, where the vast majority of Canadian production occurs.[9] The APMC handles all Alberta Crown production, NORP freehold production,[10] and any freehold production given over to it for distribution by smaller producers. The Commission pays the New Oil Reference Price (NORP) to the producer, sells it at the Conventional Old Oil Price (COOP), and receives the NORP supplement from the federal government after the condensate has been distributed (COOP production does not receive the NORP supplement). More specifically, the price of condensate to refiners is COOP plus the petroleum compensation charge, plus the Canadian ownership charge, plus associated transportation costs. As of July 1984, this price was approximately $191.80 plus $23.66 plus $7.24 plus $6.55 (Edmonton to Sarnia), respectively, for a total of $229.25 per cubic metre. The price for export is COOP, plus the relevant NEB export tariff, plus transportation costs.

NORP diluent prices are derived by assigning 52 international crudes to D/S blocks in an 81-block matrix of 9 different D (density) and S (sulphur) values. Prices are derived for the missing 29 blocks by prorating prices in adjacent blocks according to relative density and sulphur content. D1S1 is the lightest, sweetest crude possible and is the block used for pricing condensate. The D1S1 price is based on the average price of Algerian and Santa Rosa light sweet crudes which are generally below and above the average D1S1, respectively. On this basis, condensate is generally priced higher than other light crude oils since low sulphur and density levels generally command a premium due to the relatively simple refining processes required. As will be discussed later, other factors have reversed this pricing rule such that condensate is currently selling at a discount rather than a premium.

Pentanes plus were initially priced according to the petroleum industry's method of a fixed price adjusted for sulphur and light ends content. However, after six months this method was dropped by the APMC as the light ends content was generally low, relatively constant, and therefore not a major factor in pricing.

6.3.2 World Condensate Pricing

The world market situation with respect to condensate is entirely different from that of Alberta. Although OPEC imposes both production and price constraints on crude oil in general, no such constraints apply to condensate. In fact, some OPEC producers are using condensate to increase their revenues without exceeding their crude oil quotas.[11]

OPEC condensate production as of February 1984 was about 110 000 cubic metres per day, up some 16 000 cubic metres per day from the previous year.[12] Production is forecast to increase by between 24 000 and 32 000 cubic metres per day over the next few years. The Organization is beginning to take note of these volumes, not because of their size, but because of their potential to offset some of the forecast increase in demand for OPEC crude oil.

World crude oil pricing mechanisms generally afford a premium for lighter crude oils (higher API gravities), but condensate at 60° API is an anomaly, currently selling at the same level as OPEC's marker crude at 34° API. The reason for this is refiners' demand for mixed (i.e., light and heavy) product yields rather than the close to 100 percent light product yield of condensate. Moreover, condensate can alter the refining process and require additional blending, adding extra costs to refining operations. The net result is that condensate is selling at a discount rather than a premium, relative to conventional light crude oil.

The U.S. situation is similar. Gasoline demand, which largely affects refiners' demand, is the driving force for condensate feedstock prices. Although market prices for condensate are based on prices posted by refiners, they are very sensitive to supply levels as refiners are careful to ensure themselves of domestic supply. Although the U.S. imports condensate (primarily from Algeria), competition is high among refiners for domestic production for reasons of security of supply. Thus, condensate prices in the U.S. are fairly volatile due to variations in both domestic and imported supply coupled with changing demand requirements.

6.3.3 Comparative Pricing

Since the official Canadian (NORP) price for condensate is based on the world price, it can be argued that it is equivalent to the free market price (assuming that the world market can be so designated). APMC sources indicate that the effective regulated price (COOP) adjusted by transportation costs and other charges paid by Canadian and U.S. purchasers is lower than the NORP and the U.S. price for condensates.[13]

However, it has been argued that because our supply is not actually available to the world market beyond the United States, and because demand considerations are unique to this part of the world, the Canadian pentanes plus price need not track the world price. The problem with this argument lies in the nature of the regulated price. The price is not necessarily based on supply and demand and therefore it is not likely to reflect Canada's unique situation. Given the limited supply and increasing demand for pentanes plus, the regulated price is imposing an artificial ceiling on a low price. If this is the case, more pentanes plus will be used than would be at a higher price, insufficient research and development will be undertaken for alternatives, and the potential supply of pentanes plus will be prematurely depleted. Deregulation would presumably increase the price to its economically efficient (market clearing) level. As a minimum, the price would probably increase to world price (NORP) levels.

While deregulation is very much an issue at this time, the effects of such a move are not clear-cut. The actual extent of the deregulation will itself help determine the outcome.[14] Other constraints, such as the maximum price refiners are willing to pay for the blend and the minimum margin heavy crude oil producers could accept, would likely serve to keep prices from excessive increases. Also, a price increase would presumably increase research efforts in the area of alternatives.

Because of the potential need for alternatives to pentanes plus as diluent, the cost of alternatives is, and will continue to be, an issue regardless of whether or not condensate pricing is eventually deregulated. Despite the approval recently given to Husky Oil for building an upgrader, the economics of upgrading as a means of facilitating heavy crude oil transportation are not universally agreed upon. Hot oil pipelining does not appear to be economically viable at this time either, at least not over the distances and terrain that would be involved in moving Canadian heavy crude oil to Eastern Canadian or U.S. refiners. Alternate diluents are the most likely candidates, but the limited supply of light crude oils and the high cost of new technology will likely place many of these alternatives out of reach economically. In general, condensate remains the most economical diluent currently available.

Obviously, the price of diluent (either pentanes plus or some alternative) will impact the market for heavy crude oil. Even if condensate pricing is not deregulated, the limited potential supply will eventually cause prices to rise, decreasing the netback on heavy crude oil, and therefore the margin available to heavy crude oil producers. It is likely that the demand level for Canadian heavy crude oil would hold even with some increase in its price, but the possibility of shut-in supply remains. It is also possible that limits on condensate supply rather than price limitations will become the determining factor as pentanes plus become scarce. Given Canada's large reserves of heavy crude oil and bitumen and the outlook for heavy crude oil demand, alternative diluents will become increasingly important.

6.4 Alternatives to Condensate Diluents

In light of the forecast shortage of pentanes plus for use as heavy crude oil diluent, alternatives are being considered by industry and government. The possibilities fall into two general categories: alternative diluents and alternatives to diluents. These and other possible solutions are discussed in this section.

6.4.1 Alternative Diluents

Blending heavy crude oil with diluent must result in a product compatible with refinery capacity and requirements. Moreover, the blend must meet viscosity and other specifications of the pipeline company. Thus, while several alternative diluents have been proposed, only a limited number are feasible.

Drag reducing additives, or pour-point depressants, can be used as diluents with waxy crude oils, but not with the asphaltic and other similar heavy crude oils typical of Canada.[15] However, a polymer additive has recently been identified that permits transportation of heavy crude oil over long distances as an oil/water emulsion through a conventional, ambient temperature pipeline.[16] The polymer hinders coalescence (separation of the oil and water) and simultaneously keeps the oil from inverting to its original viscous state.

The blend used is composed of a 70/30 crude/aqueous solution blend with a viscosity of approximately 100 centipoise regardless of how heavy the crude oil or bitumen is. The polymer does not affect the refining process of the crude after separation, although a demulsifier would be required. A potential problem could arise if the emulsifier affects other products being transported in the pipeline because the refiners receiving these products might also need the demulsifier to separate out their products. Furthermore, the large volume of aqueous solution to be discarded after the process could pose serious difficulties for the refiners, particularly where environmental limitations in terms of limited water supply and/or legislation preclude simple disposal.

The most obvious and seemingly simplest alternatives are other light hydrocarbons such as naphtha or light or synthetic crude oil. Because of their relatively lower viscosities, greater amounts of diluent would be required than if condensate were used.[17] However, the merit of these options is debatable because light crude oil is forecast to be in limited supply in the near future and, even with sufficient supply, U.S. refineries are reluctant to accept additional light end products because it alters their processing requirements and may involve some debottlenecking.[18] Synthetic crude oil, in particular, may be received in limited amounts by conventional refineries, although the newly constructed Shell Scotford refinery is designed to operate solely on synthetic crude. Thus, the viability of these alternatives appears limited.[19]

6.4.2 Alternatives to Diluents

Several constraints are automatically imposed with the use of diluents including the reluctance of refiners to accept light end products with heavy crude oil and supply limitations. Consequently, research is being done into ways to eliminate the need for diluents, or to at least diminish that need. Hot oil pipelines and upgrading are two such possibilities.

Hot oil pipelining requires special pipeline design considerations regarding heating of the line (both insulation and heat loss to the environment) and the operation of the line (including possible expansion or contraction of the pipeline and the need for displacement oil during cooldown). Researchers are currently working on the concept of converting pipelines designed to carry crude oil at ambient temperatures to accommodate hot oil.[20] Although several hot oil pipelines have been successfully constructed and operated,[21] the economics and feasibility of a conversion process such as the one mentioned, particularly over such a long distance and in a relatively cold climate, are unclear.

Upgrading is not so much an alternative to using diluent as a means of decreasing diluent demand. In fact, if a heavy crude oil upgrader used incremental production, it would require some diluent itself. However, this would be a one-time demand because the diluent would likely be recycled from the plant back to the field.[22] Thereafter, the upgrader would decrease diluent demand to the extent that it offsets diluent that would otherwise have been exported with the heavy crude oil.

A similar solution would involve upgrading existing refinery facilities to enable processing of heavy crude oil. The resulting light product flows could then be transported by conventional means to various markets.

Partial upgrading of heavy crude oil is a further possibility currently being evaluated by several companies. This would presumably involve a lower level of capital investment and a lower-cost process. Depending on the extent of the process, the resulting heavy crude oil would either require less diluent or be pipelineable as is.

6.4.3 Alternative Solutions

Several other alternatives are available to increase the amount of condensate available for diluent use.

First, the amount of currently "unavailable" supply could be reduced. The condensate used in miscible flooding would likely continue to be used as such, but at least some of the volume currently transported to the U.S. through the Rangeland Pipeline could probably be transported north by truck or rail or by a newly constructed line.

Another stream that could potentially release some condensate for diluent use is the NGL stream flowing to Eastern Canadian refineries. The condensate could be separated in Alberta for diluent use but some other light end product (i.e., synthetic crude, naphtha) would have to be added back in to the NGL stream to keep the vapour pressure of the mixture within pipeline and refinery standards. Industry sources indicate that this possibility is currently being investigated. The other alternative would be to upgrade the existing pipeline and refinery facilities to handle the additional vapour pressure. However, the cost of such an endeavour is currently unknown.

A second alternative is to import condensate from the world and/or U.S. market. Canada has imported condensate for eastern refineries, but transporting it to Lloydminster would be much more complex. As no pipeline currently flows north to the Edmonton area, the least cost alternative would likely be tanker transport to Vancouver and truck or rail transport thereafter. Cost estimates for rail transport from the West Coast to Lloydminster range from $57 to $59 per cubic metre. Given a (COOP) price of about $190 per cubic metre, these costs amount to an additional 30 percent and likely preclude this possibility.

Finally, a pipeline loop could be built to return the condensate back to the producing area from the U.S. or Eastern Canadian refineries. It is unlikely that this option would be less costly than the other alternatives already mentioned. A more likely alternative is for pipeline companies to increase the horsepower of their lines and/or make other improvements to accommodate flows of heavier crude oils.

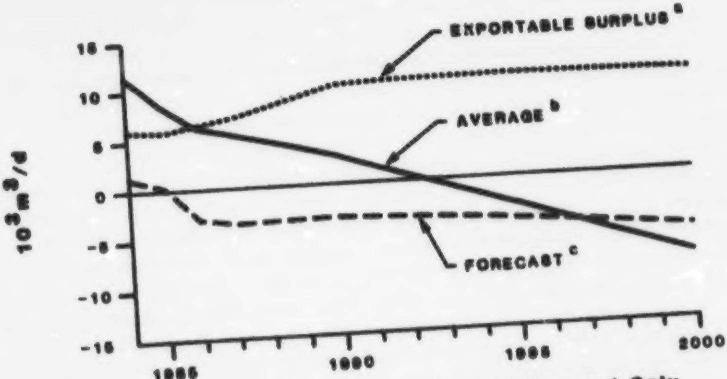
6.5 Summary and Conclusions

Production of heavy crude oil is dependent on diluent insofar as it is required to transport the crude to market. Pentanes plus are currently the best available diluent for heavy crude oil. However, shortages of pentanes plus forecast in the late 1980s could potentially limit the development of Canada's heavy crude resources. Regulation of the distribution of pentanes plus likely causes some market distortions, but price regulation probably has a greater effect through undervaluing the limited supply of condensate. Deregulation would probably increase the price of pentanes plus and thereby encourage research into the use of alternatives. Many alternatives are not economically viable at this time and the higher cost associated with others (e.g., naphthas and light crudes) could limit development of the heavy crude oil resource base. Nevertheless, alternative diluents will probably play an increasing role in the near future.

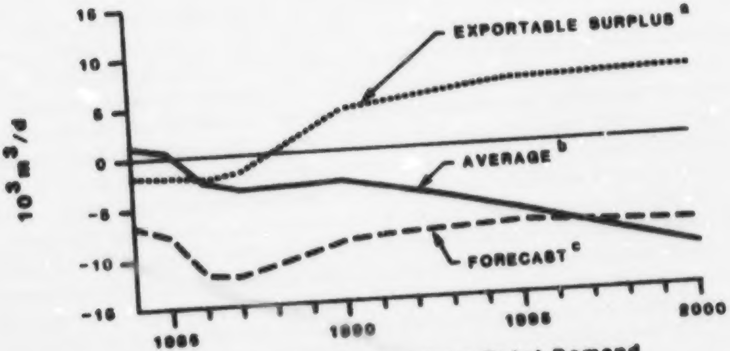
Analysis of the condensate requirements for the forecast supply and exportable surplus of Canadian heavy crude oil as derived in Chapter 4 reveals that the long-term condensate supply shortfall may indeed be less than anticipated. Total diluent requirements for the total supply of conventional heavy crude oil and bitumen will increase at an average annual rate of 1.4 percent from 1985 to 2000 as opposed to an annual increase of 8.7 percent for the same period based on the average demand of the studies previously discussed (see Table E.5). If the diluent component for only the exportable surplus of Canadian heavy crude oil is considered, the diluent requirement actually decreases at an average annual rate of almost 10 percent between 1985 and 2000.

Subtracting these demand figures from the average forecast supply figures obtained earlier (see Table E.2) yields the forecast net supply/demand balance for Canadian pentanes plus for heavy crude oil diluent (see Figure 6.5 and Table 6.1). The average figures indicate a shortfall of 2600 cubic metres per day as early as 1986 which increases to over 11 000 cubic metres per day by 2000. Comparable figures based on the forecast from Chapter 4 show an immediate shortfall which peaks in 1987 but then falls to 8500 cubic metres per day by 2000. The volume of condensate required as diluent for heavy crude oil and bitumen used domestically would be smaller than that required for export due to the shorter distances involved on the average, and because these volumes would likely be recycled back to the point of origin and reused. Using the assumption that condensate diluent would be required only for the exportable surplus, the supply shortfall almost disappears and actually only lasts until the late 1980s.

These results must be tempered on at least two counts. On the one hand, the net balance may be high in that some condensate diluent would be required domestically both as initial volumes for incremental heavy crude oil production and as replacement volumes for amounts lost in transit and segregating operations. This would mean a larger shortfall initially that would possibly last longer. On the other hand, if the proportion of the bitumen component of the exportable



S/D Balance based on Diluent Demand Only



S/D Balance based on Total Demand

SOURCE: Table 6.1.

NOTE: [a] Average supply less diluent requirements for the exportable surplus of Canadian heavy crude oil only.
[b] Average supply less average forecast diluent demand.
[c] Average supply less diluent requirements for the forecast total Canadian heavy crude oil production.

FIGURE 6.5: DILUENT SUPPLY/DEMAND BALANCE FOR CANADIAN HEAVY CRUDE OIL: 1984-2000

TABLE 6.1

DILUENT SUPPLY/DEMAND BALANCE FOR FORECAST CANADIAN HEAVY CRUDE OIL PRODUCTION

1984-2000
($10^3 m^3/d$)

Year	Avg. Supply (Base Case)[a]	Average Demand (Base Case)[b]		S/D Balance[c]		Forecast Total Demand[d]		S/D Balance[c]		Exportable Surplus Demand[e]		S/D Balance[c]	
		Diluent	Total	Diluent	Total	Diluent	Total	Diluent	Total	Diluent	Total	Diluent	Total
1984	13.9	4.7	12.6	11.2	1.3	12.7	20.6	1.2	(6.7)	7.8	15.7	6.1	(1.8)
1985	14.1	5.7	13.5	8.4	0.6	13.9	21.7	0.2	(7.6)	8.3	16.1	5.8	(2.0)
1986	14.5	8.4	17.1	6.1	(2.6)	17.6	26.3	(3.1)	(11.8)	8.1	16.8	6.4	(2.3)
1987	14.4	9.1	17.7	5.3	(3.3)	17.9	26.5	(3.5)	(12.1)	7.4	16.0	7.0	(1.6)
1990	14.8	12.1	17.9	2.7	(3.1)	18.1	23.9	(3.3)	(9.1)	4.9	10.7	9.9	4.1
1995	14.0	16.8	20.6	(2.8)	(6.6)	18.1	21.9	(4.1)	(7.9)	3.7	7.5	10.3	6.5
2000	11.5	19.8	22.6	(8.3)	(11.1)	17.2	20.0	(5.7)	(8.5)	1.8	4.6	9.7	6.9

SOURCES: (1) Table E.2, E.3, and E.5; (2) Foster Research, "The Forecast Supply and Demand for Alberta Condensate for Blending with Heavy Crude Oil 1984-2000," (Calgary: Foster Research, 1984), p. 30; and (3) Hycarb Engineering Ltd., *Canadian Heavy Crude Oil Market Analysis* (Calgary: Hycarb Engineering Ltd., 1984), p. 125.

[a] Average diluent supply based on forecasts from Table E.2.

[b] Average diluent demand based on forecasts from Table E.3.

[c] Supply less demand.

[d] Forecast total demand based on diluent requirements for the synthesized forecast supply of Canadian heavy crude oil as calculated in Table E.5. Total based on forecast diluent demand from Table E.5, plus total average demand net of diluent component.

[e] Assumes diluent required only for Canadian heavy crude oil exportable surplus volumes. Total based on forecast diluent demand for exportable surplus from Table E.5, plus total average demand net of diluent component.

surplus was lower, or the conservative estimate of 50 percent diluent used with bitumen was high, the forecast shortfall could disappear.

Despite the various arguments, the availability of condensate for use as diluent does not seem to be an obstacle to moving the exportable surplus of Canadian heavy crude oil to markets in the northeastern United States. Given available supply, market demand, and adequate logistics, the only remaining consideration is price. The following chapter will summarize all these elements and provide illustrative calculations of the prices and costs involved in exporting Canadian heavy crude oil to the United States.

Footnotes

[1] Condensate is a liquid hydrocarbon that is recovered from a well. Pentanes plus is a liquid hydrocarbon obtained by processing raw gas, condensate, or crude oil. See Alberta Energy Resources Conservation Board, The Oil and Gas Conservation Act (Office Consolidation) (Calgary: Energy Resources Conservation Board, 1982), Section 1(1) (d.1) and Section 1(1) (p). These terms are generally used interchangeably in this study and elsewhere.

[2] Alberta Energy Resources Conservation Board, Alberta Oil Supply 1983-2007, Report 83-E (Calgary: Energy Resources Conservation Board, 1983), p. 8. Supply level estimated for 1983 is based on the figures in Table 6.1.

[3] Legislation is currently in place in Alberta that would require all pentanes plus production from Crown lands to be segregated out and given to the Alberta Petroleum Marketing Commission (APMC) for distribution. However, this will not likely be implemented due to the onerous costs involved for the petroleum companies. Should the demand for and price of condensate increase sufficiently, it is possible that extracting some or all of the flow to Eastern Canada (as NGL buffer) and to the U.S. (as part of the export stream) could become economic. However, new technologies for propane/butane and for pentanes plus transportation would probably also be necessary. For the purpose of this report, these streams are assumed to continue to flow to Eastern Canada and the U.S., and remain as constraints on potential supply.

[4] Foster Research, The Forecast Supply and Demand for Alberta Condensate for Blending with Heavy Crude Oil 1984-2000 (Calgary: Foster Research, 1984), p. 30 (CERI calculations). Unavailable supply is forecast to hold at 40 to 45 percent in the Foster study to the year 2000, whereas the Hycarb study forecasts a decline to about 10 percent by the year 2000. See Hycarb Engineering Ltd., Canadian Heavy Crude Oil Market Analysis (Calgary: Hycarb Engineering Ltd., 1984), p. 125. See also G. R. Crandall and T. H. Wise, "Market Outlook for Canadian Heavy Crude," The Journal of Canadian Petroleum Technology, May-June 1984, pp. 67-71. This paper is based on the analysis contained in the Hycarb multi-client study referenced above.

[5] The consensus opinion is that recovery rates will decrease in the short term. In the long term, however, the ERCB predicts an increase in the ratio as deferred reserves with high liquid content are brought on stream. Recovery ratios were obtained from ERCB data by dividing net pentanes plus production by (marketable) gas production and from the Hycarb study. See Alberta Energy Resources Conservation Board, Alberta Oil Supply, 1983-2007, p. 23, and Hycarb Engineering Ltd., Canadian Heavy Crude Oil Market Analysis, p. 121.

[6] No attempt was made to provide independent supply or demand forecasts because time and resources prohibited the extensive analysis

required for such undertaking. However, based on analysis to date, CERI expects a gradual decline in supply to 2000.

[7] We have assumed that gas exports will increase in the late 1980s.

[8] For example, the amount of pentanes plus added to a given volume of Lloydminster heavy crude oil is about 30 percent of that volume, yielding about a 77/23 crude/condensate ratio in the total blend. Alberta bitumen requires the addition of 43 or 50 percent pentanes plus to a given volume of bitumen, yielding 30 or 33 percent condensate in the total blend. See Foster Research, The Forecast Supply and Demand for Alberta Condensate, pp. 11-13.

[9] Saskatchewan and British Columbia produce minimal amounts of condensate which are sold on the open market.

[10] NORP applies to petroleum discovered after April 1, 1974. Freehold producers of NORP condensate are not required by law to sell their production to the APMC. However, in that case, the producer does not receive the NORP supplement.

[11] "Condensate Sales Blooming Despite Oil Output Restraints," Petroleum Intelligence Weekly, February 27, 1984, pp. 1-2.

[12] Ibid., p. 7. Precise figures of world condensate production and demand are difficult to obtain as condensate is often categorized as crude NGL and included as some unknown percentage of these streams. Moreover, some condensate production is returned to and sold with crude oil streams rather than being marketed as a separate commodity. That different countries employ different practices makes identification of condensate that much more complicated.

[13] The NORP price could also be considered low in that it is based on prices for light crudes with API gravities lower than that of condensate since light crude oils generally command a premium. However, this argument does not hold in the present situation in that condensate is currently selling worldwide at a discount rather than a premium to light crude oil.

[14] The APMC has indicated that the "priority list" would likely remain intact even with condensate price deregulation. Moreover, the agreement with the Shell Bowden refinery would still be enforced should the list also be done away with. History has revealed that with a surplus the price for pentanes plus falls below light crude oil prices indicating that it is sensitive to market forces.

[15] Dean Hale, "Drag Reducers, Flow Improvers, and Other Magic Potions: Slick Way to Increase Capacity," Pipeline and Gas Journal, June 1984, p. 19. Also, V. R. Withers and R. T. L. Mowll, "Techniques for Predicting Flow of Viscous Oils in Pipelines," in The Future of Heavy Crude and Tar Sands: Second International Conference, edited by

R. F. Meyer et al. (New York: McGraw-Hill, Inc., 1984), pp. 1310-1311.

[16] Dean Hale, "Drag Reducers, Flow Improvers, and Other Magic Potions," p. 19. Also, "Polymer Allows Shipment of Heavy Oil, Water," *Oil and Gas Journal*, April 2, 1984, p. 74.

[17] "The lighter the diluent, the greater the viscosity of the resulting blend and the lower the amount of diluent required." This is not a strictly linear relationship. The relationship between the barrels of diluent required per barrel of heavy crude oil is given as

$$\frac{P-D}{M-D} - 1$$

where P is the specific gravity of the heavy crude oil formation, D is the specific gravity of the diluent and M is the specific gravity of the blended oil. See Hernan Cabrera, "Production and Transport of Heavy Oils by Blending with Lighter Crudes," in *The Future of Heavy Crude and Tar Sands: Second International Conference*, p. 1299.

[18] The extent of the impact of this latter argument varies among refiners according to their particular capacity for heavy crude oil. The demand for heavy crude oil is considered to be such that the refiners would be willing to accept limited amounts of light end products to obtain their desired amount of heavy crude.

[19] Despite the fact that "market prices for combined blended crudes have generally been more advantageous than the summation of crude prices for the individual components," the aforementioned supply and demand limitations will likely negate this advantage. (See Cabrera, "Production and Transport of Heavy Oils by Blending with Lighter Crudes," p. 1302). Thus, even if under deregulation condensate prices exceeded the prices for other DISI crudes, only a limited amount of substitution would take place.

[20] See Philippe Regnaud and Christian Allain, "Converting Pipelines to Hot Product Transportation," *Oil and Gas Journal*, May 28, 1984, pp. 107-110. Unfortunately, no definite conclusions seem to be drawn in this article.

[21] For example, the Alyeska 48-inch pipeline in Alaska transports crude oil some 800 miles at 160°F. BP transports heavy crude oil some 320 miles at 130°F through a 30-inch line in Libya. See A. Sloan et al., "Pipeline Transportation of Heavy Oils," *The Future of Heavy Crude and Tar Sands: First International Conference*, edited by R. F. Meyer and C. T. Steele (New York: McGraw-Hill Inc., 1981), p. 720.

[22] The diluent requirement will depend on the proximity of the plant to the field and the amount of flow between them. It has

been suggested that an upgrader may actually produce some diluent itself which could be used either within the recycling process or to take the heavy crude oil to market. See J. M. Wilkinson, "Introduction to Heavy Oil Upgrading" in The Future of Heavy Crude and Tar Sands: First International Conference, pp. 596 and 600.

Chapter 7

SUMMARY AND CONCLUDING OBSERVATIONS

7.1 Introduction

This chapter contains a summary, some concluding observations, and comments on implications for Canadian energy policy and heavy oil marketing based on the analysis in this study. An illustrative calculation of netbacks to the producer at the wellhead is also presented together with comments on the effect of price deregulation. Finally, some concluding comments and observations are made regarding the U.S. demand for Canadian heavy crude oil; the Canadian demand for Canadian heavy crude oil; the supply of Canadian heavy crude oil; the impact of crude oil price and price differentials; and suggestions for further work.

7.2 Illustrative Calculations of a Producer's Netback at the Wellhead

Illustrative calculations of a producer's netback at the wellhead on the sale of a cubic metre of Canadian heavy crude oil in the Chicago market are presented in Tables 7.1 and 7.2 for the regulated and deregulated cases, respectively. "Netback" is simply the value a producer would realize at the wellhead before any deductions of production costs or fiscal levies. Although these calculations are intended for illustration only, the data used are as accurate and representative as possible relative to those in effect in August of 1984.

An interesting comparison can be made between the regulated and deregulated cases shown in the two tables. The immediate effect of deregulation of the Canadian heavy crude oil market seems to be a reduction of netbacks for both Lloydminster- and Cold Lake-types of heavy crude oil. This is due to the decrease in heavy crude oil prices and the increase in diluent prices expected to occur with deregulation. Specifically, producers will lose their NORP supplement and encounter greater deblending cost adjustments, although the effect of these will be somewhat offset by the elimination of the NEB export charge. For illustration, Table 7.1 shows the average netbacks under the current regime based on both COOP and NORP prices.

TABLE 7.1

ILLUSTRATIVE CALCULATION OF PRODUCER'S WELLHEAD NETBACK AS OF AUGUST 1984 REGULATED CASE: CHICAGO MARKET ($/m^3)

	Heavy Crude Oil Source	
Destination: Chicago	Lloydminster	Cold Lake
Market Price of Blend	$215.12	$214.35
Less: U.S. Customs Duty	0.43	0.46
Pipeline Tariffs and Allowances	7.22	7.50
NEB Export Charge	29.15	16.00
The Value of Blend at Hardisty/Edmonton	178.32	190.39
Less: Avg. Cost of Moving Blended Oil From Hardisty/Edmonton to Pipeline Terminus	9.21	21.27
Value of Blend at Pipeline Terminus	169.11	169.12
Less: Deblending Adjustment[a]	7.56	9.72
COOP Value of Crude at Pipeline Terminus[b]	$161.55	$159.40
Plus: NORP Supplement	43.40	33.15
NORP Value of Crude at Pipeline Terminus	$204.95	$192.55
Less: Average Field Movement Charges[c]	8.00	16.50
Average Netback to the Producer at Wellhead Based on NORP	$196.95	$176.05
Average Netback to the Producer at Wellhead Based on COOP	$153.55	$142.90

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[a] See Table 7.2 for details. COOP value for D151 has been used in this table for VD.

[b] These COOP values correspond to D859 and D959 for Lloydminster- and Cold Lake-types of heavy crudes, respectively; they reflect the amount producers receive when delivering heavy crude oil from wellhead to a pipeline terminus for blending with diluent and subsequent shipment.

[c] These are average values representing the producer's cost of transporting crude oil from the wellhead to the pipeline terminus; they can vary considerably from being very small to up to $30/m^3. Typically, these costs will be higher for Cold Lake-type crude oil.

TABLE 7.2

ILLUSTRATIVE CALCULATION OF PRODUCER'S WELLHEAD NETBACK AS OF AUGUST 1984 DEREGULATED CASE: CHICAGO MARKET ($\$/m^3$)

	Heavy Crude Oil Source	
Destination: Chicago	Lloydminster	Cold Lake
Market Price of Blend	$215.12	$214.35
Less: U.S. Customs Duty	0.43	0.46
Pipeline Tariffs and Allowances	7.22	7.50
Value of Blend at Hardisty/Edmonton	207.47	206.39
Less: Avg. Cost of Moving Blend From Hardisty/Edmonton to Pipeline Terminus	9.21	21.27
Value of Blend at Pipeline Terminus	198.26	185.12
Less: Deblending Adjustment[a]	20.01	31.36
Value of Crude Oil at Pipeline Terminus	178.25	153.76
Less: Avg. Field Movement Charges	8.00	16.50
Avg. Netback to the Producer at Wellhead	$170.25	$137.26

[a] This is calculated using the following formula:

$$VC = \frac{VB - (VD \times PD)}{PC}$$

where, VC is the value of the crude oil in the blend; VB is the value of the blend; VD is the value of diluent; and PD and PC are the percentages of diluent and crude oil in the blend, respectively. The value of VC is then subtracted from VB to obtain deblending adjustment. NORP value for D1S1 has been used in this table for VD (see also note to Table 7.1).

The magnitude of these changes brings into question the economic effectiveness of the current administration under which the NEB, rather than the producer, in effect markets Canadian heavy crude oil in the U.S. Thus, the netback values from the deregulated case in Table 7.2 are more reflective of the actual worth of Canadian heavy crude oil in the U.S. market. It can be seen that the deregulated netback on Lloydminster-type heavy crude oil production may fall somewhere between the COOP ($161.55 per cubic metre) and NORP ($204.95 per cubic metre) values as of the summer of 1984, while the netback from Cold Lake production under deregulation is considerably lower when compared with the current regulated case. This would suggest that, given the assumptions contained in the netback calculations, under deregulation, some production of Cold Lake heavy crude oil could be rendered only marginally economic or possibly be shut in as economically unattractive. To the extent that about 74 percent of Canadian heavy crude oil production received NORP prices in 1984, the effect of deregulation on producers' returns could be significant. A complete review of production costs, however, would be required in order to accurately determine the profitability of any heavy oil production.

What seems clear is that, in the short term under deregulation, the market price of diluent will rise from its current COOP level toward NORP and, depending on the level of condensate demand in the petrochemical sector, possibly above NORP. This would have the effect of reducing the heavy oil producer's netback via a higher value of the deblending adjustment (see Table 7.2).[1]

With respect to the question of marketing heavy crude oil under deregulation, much would depend on the actual form and extent of deregulation. At present, all marketing is done effectively at the COOP level, with the NORP supplement being just a straight fiscal transfer from the federal Petroleum Compensation Charge account to the provinces. The actual effect of deregulation on heavy crude oil producers would largely depend on the particular role the Alberta Petroleum Marketing Commission (APMC) would play regarding the marketing of diluent.[2] Under deregulation, heavy crude oil producers would likely have to secure their own diluent and, as argued above, that price could be expected to increase in the short term from the current COOP level to somewhere between COOP and NORP or possibly even above NORP. The net effect will also depend on whether or not the current priority list for distributing pentanes plus would be totally eliminated.

7.3 U.S. Demand for Canadian Heavy Crude Oil

7.3.1 Expansion of Established Markets

Three U.S. refineries currently accept about 85 percent of all Canadian heavy crude oil exports to the U.S. These are the Koch refinery in Pine Bend, Minnesota, the Mobil refinery in Joliet, Illinois, and the Amoco refinery in Whiting, Indiana. Neither these refineries nor the total group of U.S. refineries currently importing Canadian heavy crude oil have a great deal of available capacity to accept additional Canadian exports. The potential for displacing other imported heavy crudes in these refineries is limited since Canadian heavy crudes are already the dominant imported feedstock. Since there is no publicly available information on the deliveries of United States domestic heavy crude oil, the market expansion potential which could be realized by displacing other crude supply sources cannot be identified. Given normal market conditions, price reductions in Canadian heavy crudes at the market interface (i.e., current and potential new markets) would likely be required to displace U.S. domestic heavy crude oil by Canadian heavy crude oil. This fact is supported by recent decreases in nominations for Canadian heavy crude oil by some U.S. refineries attributed to relatively high Canadian prices.

Although a refiner's heavy crude oil throughput capacity based on the refinery configuration may be identified with some degree of accuracy, this process has not been undertaken in this paper due to the complexity associated with identifying the impact of alternative crude oil slates on refinery throughput constraints and the resultant product slates. As a result, the specific volumes of U.S. domestic crudes that could be displaced are not determined since the necessary data are not readily available by refinery or by state.

7.3.2 Expanding the Market for Canadian Heavy Crude Oil

As shown in Chapter 5, there could be a very large market to tap by shifting the market interface for Canadian crude oil from Chicago to the Patoka/Wood River area in Illinois. This potential is measured by the volume of imported offshore heavy crude oil that is currently utilized in this market and could be potentially displaced by Canadian heavy crude oil. Again, neither the volumes of U.S. domestic heavy crude oil nor the amount of other foreign heavy crude oil imports that might be displaced in this area could be identified due to data limitations.

The potential of this market could be limited in that fairly significant capital expenditures would be required to either reverse the flow of an existing pipeline or to construct a new pipeline that could move Canadian heavy crude oil from the Chicago market to Patoka. In addition, the netback to the Canadian producer would decrease due to: (i) the increased transportation charges associated with reaching the market; and (ii) the lower prices which might be required to induce market penetration and displace alternative crude oil supply sources. On the other hand, the lower prices may be offset if the degree of subsidization incurred by the Canadian government were to increase under the current pricing regime. Moreover, a lower price at the market interface would presumably be reflected at all points between the wellhead and the new market interface resulting in incremental sales in already established markets. However, incremental volumes sold in these markets would likely be small due to the current market structure.

7.3.3 Deliverability Constraints Associated with U.S. Market Expansion

The major short-term constraints to increased Canadian penetration of the U.S. heavy crude oil market are the possible bottleneck on the IPL pipeline to Chicago, the potential shortage of Canadian diluent, the increasingly heavy composition of Canadian crude oil exports, and the lack of a delivery system from Chicago to Patoka.

Constraints on the IPL pipeline will be exacerbated by increasing the volume of heavy crude oil relative to light shipped through the line. However, IPL's current expansion plans are expected to offset this effect such that a portion of normal excess capacity will be restored by the end of 1985.

Under the current production/export scenario, a pentanes plus diluent shortage is expected sometime between 1986 and 1992, depending on particular assumptions. The problem of a diluent shortage would become increasingly serious as the composition of the heavy crude oil export slate tends toward heavier crude oil supply sources as larger volumes of diluent are required per unit of crude.

Most of the NEB submissions and studies reviewed in this study forecast shortfalls in condensate supply as early as the mid-1980s.[3] The expected impact of diluent supply on heavy crude oil production and marketing varied with each submission's views on the possibility of finding adequate supplies of alternative diluents, and on the possible future revival of natural gas markets which, in turn, would have a positive effect on forecast pentanes plus supplies.

The majority of the studies and submissions reviewed accepted alternative diluents as appropriate solutions to expected shortfalls in condensate supply with varying degrees of skepticism. Some submitters were confident that alternative diluents would be available,[4] while others emphasized that further comprehensive research was needed before accurate predictions could be made.[5] The future availability of alternative diluents will depend on their own market and production environments, particularly in the case of diluent market deregulation.

In any case, it appears that the supply of diluent will affect Canadian heavy crude oil production and marketing, and will likely prove to be a restraining factor. First, diluent supply could have a limiting influence on the movement of future bitumen production[6] and, therefore, have an indirect effect on the development of that resource. Second, diluent availability could be an important factor in determining U.S. demand for Canadian heavy crude oil.[7] Third, diluent supply will be a primary consideration in decisions regarding the export versus upgrading of Canadian heavy crude oil. If no alternative for pentanes plus is found, upgrading or partial upgrading of heavy crude oil may be required,[8] making diluent availability the pivot upon which decisions concerning the upgrading or exporting of heavy crude oil may turn. Finally, diluent supply could influence government policy. Recent approvals for heavy crude oil production development at Cold Lake and Elk Point will put pressure on governments to solve diluent supply-related problems. Governments may provide subsidies to cover the cost of diluents in order to make Canadian heavy crude oil economic in U.S. markets. On the other hand, government support could occur in the form of fiscal system changes for what could otherwise be uneconomic upgrading developments.

The lack of an available delivery system in the U.S. to move increased Canadian heavy crude oil exports to potential new markets is probably the most serious limitation to potential increases in Canadian heavy crude oil exports. A prime concern associated with undertaking the construction of a delivery system is whether or not U.S demand for

Canadian heavy crude oil will be sufficient and relatively stable over an adequate time period. The effect of the U.S. road paving program on current U.S. demand for heavy crude oil and the impact its curtailment will have on this demand is uncertain. This is an important consideration since a large portion of U.S. demand for Canadian heavy crude oil is for asphalt rather than production of light petroleum products.

7.4 Canadian Demand for Canadian Heavy Crude Oil

Given the current pricing regime in Canada and the institutional arrangement regarding Mexican heavy crude oil imports, limited opportunities exist for increasing the use of Canadian heavy crude oil by conventional Canadian refiners. Moreover, due to data limitations regarding the source of crude oil supply by refiner and by province, it is not possible to accurately identify the crude oil supply sources which could be displaced or their magnitudes.

The impact of Canadian refinery configuration on the demand for Canadian heavy crude oil has in large part been determined by recent refinery rationalization and its results--complete and partial refinery shut-downs. According to Hycarb Engineering Ltd., these major changes in the configuration of the Canadian refining industry will produce a decrease in refining capacity of 71 200 cubic metres per day in the Eastern region and a net increase of 10 650 cubic metres per day in the Western region of Canada.[9] Other sources confirm these views on future trends in Canadian refinery configuration.[10]

Despite, the positive influence of these changes in the Canadian refining industry on the demand for Canadian heavy crude oil, refinery demand for domestic heavy crude is expected to remain relatively low. Nominations for Canadian heavy crude oil by Canadian refineries have historically only amounted to between 2 and 10 percent of total refinery capacity.

While nominations and capacity figures provide some indication of the expected demand for Canadian heavy crude oil, they do not provide accurate estimates of actual refinery demand. Delivery information categorized by refinery and crude types would provide the basis for accurate estimation of the Canadian demand for heavy crude oil and how this demand is influenced by refinery configurations, but such data are not available in the public domain. What can be said is that given available information and the current configuration of conventional Canadian refineries, the potential for increased utilization of Canadian heavy crude oil appears limited. Increases in Canadian demand will most likely be reflected in feedstock requirements for upgraders, or partial upgraders. This demand will be constrained, however, by the ability of conventional refiners to process partially upgraded heavy crude oil or synthetic crude oil.

7.5 Supply of Canadian Heavy Crude Oil

A prerequisite for increasing Canadian heavy crude oil exports to the United States is increased production of Canadian heavy crude oil, particularly the volumes eligible for export. However, since effective U.S. demand for heavy crude oil is not easily identifed at any given moment, it is not possible to target the development of any particular supply source as being adequate for meeting future incremental requirements.

With the tendency for declining production from conventional sources, greater reliance will be placed on non-conventional reserves which are generally heavier and require special recovery techniques and higher cost conventional sources, such as thermal enhanced recovery. These recovery methods have very high capital costs relative to conventional production techniques for conventional crude oil supply sources and two to three times the operating costs. Operating costs for the new supply sources have been estimated at $60 to $120 per cubic metre. Given that aggregate production-related levies will vary between 15 to 25 percent of total revenue, these incremental supply sources could become unprofitable as a result of very small price decreases from the current level.

Recent agreements between federal and provincial governments and producers regarding the future development of Canadian heavy crude oil reserves indicate that Canadian export supply is sensitive to price. As a result of these agreements, oil from the Elk Point and Cold Lake projects will receive NORP prices, which are currently (December 1984) above world prices at the Chicago Market. According to an Energy Mines and Resources Canada spokesman, receiving NORP prices is "a bit of a push for heavy oil . . . If there was no price-setting in Canada, they would not be getting that high a price."[11] In addition, "the difference between what the U.S. will pay for Elk Point crude is made up by an export payment and by a federal subsidy."[12] These higher-than-market prices are significant components of the agreements, bringing into question the viability of future Canadian heavy crude oil developments without them or, alternatively, the viability of domestic heavy crude oil production within the current fiscal regime. Future supplies will be influenced by price and may demand fiscal regime changes or possibly government subsidies to maintain acceptable price levels.

In general terms, fiscal incentives may be required for some heavy crude oil projects because the current market price could be insufficient to support production and to accommodate both relatively high production costs and fiscal levies. While market price deregulation would provide incentives for absorbing the former, governments may have to forego some of their revenues (taxes and/or royalties) in order to encourage Canadian heavy crude oil production or upgrading. This would especially be the case if it can be agreed by the federal and provincial governments that additional heavy oil developments in Western Canada would significantly contribute to investment and employment opportunities in both Western and Eastern Canada and, in the case of heavy oil upgrading, add to Canada's oil self-sufficiency. As for the fiscal incentives within a deregulated heavy crude oil market, efficiency criteria suggest that concessions until project payout and/or reduced tax or royalty rates would be preferred to direct subsidies or price guarantees.

If significant volumes of incremental heavy crude oil are required for market expansion and the subsequent maintenance of these markets, the supply source will be the high cost oil sands. In fact, production from the oil sands will most likely be required to supply current U.S. markets for Canadian heavy crude oil due to decreases in production from Canadian conventional heavy crude oil sources. Crude oil from the oil sands is somewhat less preferred than that from conventional sources since bitumen, with an API gravity of about 10°, is blended with a higher proportion of condensate per unit. Moreover, the product slate is somewhat different for non-conventional than for conventional heavy crudes because the former tend to yield limited volumes of middle distillates and proportionately larger volumes of asphalt production.

Based on the analysis in the study, some exportable surplus of Canadian heavy crude oil is expected until the year 2000. The level of this surplus varies considerably between the low, base, and high price cases, and between the scenarios with and without upgraders. Nevertheless, only in the low price case without upgraders would no surplus be available for export. Under the base case scenario, the exportable surplus for the year 2000 amounts to 5900 cubic metres per day with upgraders, and 29 900 cubic metres per day without upgraders, based on government agency supply forecasts and industry estimates of domestic refinery feedstock demand. Thus, available supply is not expected to be a constraint on future Canadian heavy crude oil exports to the United States.

7.6 Impact of Crude Oil Price and Price Differentials

There is no generally accepted theory for determining price differentials between crudes of various qualities, or linking or relating world price differentials to those observed in local markets. In terms of individual refiners, absolute price levels are most relevant in the short term since substitution between crudes of greatly different characteristics is generally not possible in the short term, regardless of price differentials. On the other hand, perceived or expected future crude oil price differentials are most important for the long term as they affect refinery investment decisions.

From the perspective of a Canadian heavy crude oil producer, the absolute price in any local market, rather than price differentials, will be the determining factor for production levels. Given the high cost of producing Canadian heavy crude oil, small changes in absolute price will be of greater importance in determining crude oil supply than changes in price differentials, particularly if the latter are due to changes in light crude oil prices. However, the price differential between heavy and light crude oils will be critical in determining the economic viability of heavy oil upgrading.

CERI anticipates that there will likely be a difference between crude oil price differentials in the short versus the long term. In the short term, differentials may narrow further due to the current glut of light crude oils on the world market and the increasing demand for heavy crudes; in the long term, due to the expected decline of light crude oil availability relative to heavy crude oil, price differentials are expected to widen.

7.7 Implications for Canadian Energy Policy and Heavy Oil Marketing

Based on the analysis of this study, several general energy policy-related conclusions can be drawn. These are stated below in the form of suggestions for energy policy makers and for those engaged in the marketing of heavy crudes.

Deregulation of Canadian crude oil prices in both the domestic and export markets is desirable. This would have a beneficial effect in terms of increased efficiency of Canadian heavy crude oil production. In the export market, for example, U.S. buyers would be more inclined to rely on Canadian heavy crudes if they anticipated that the Canadian price would remain competitive with alternative sources. In turn, this would lead to more steady and possibly increased demand for Canadian heavy crude oil.

Lower producer netbacks from the sale of Canadian heavy crude oil to the Chicago market under the deregulation scenario discussed earlier in the chapter imply that the current regulated price has been greater than market value. This is corroborated by decreases in U.S. refinery nominations for Canadian heavy crude oil due to its relatively high price prior to the price adjustments announced by Canada in January. Price deregulation would ensure that the Canadian export price is realistic vis-a-vis competitive supplies.

Possible decreases in producers' netbacks under deregulation suggest that production by marginal producers could become uneconomic. In this way market forces would serve to encourage maximum operating efficiency in new and planned recovery operations.

Under deregulation, Canadian heavy crude oil producers and/or exporters would negotiate selling prices of Canadian heavy crude oil themselves rather than effectively deferring decisions on such matters to the National Energy Board. The loss of the NORP supplement by a producer would be partially offset by the simultaneous elimination of the Board's export change. The producer would then absorb any loss or receive any available margin.

Deregulation of condensate and pentanes plus prices and marketing rules by the Alberta Government needs to be given serious consideration. Such deregulation would improve the efficiency of condensate/pentanes plus allocation and tend to increase the volumes available as heavy oil diluent. This is important because diluent shortages forecast for as early as the late 1980s could hinder the development and transportation of Canadian heavy crude oil resources.

If deregulation of diluent prices and abandonment of the related marketing rules led to an increase in the cost of diluent, they could be expected to increase research into alternative means of transporting heavy crudes. Alternative diluents and/or alternatives to diluents could be key to Canadian heavy crude oil exports in the future. Because the current regulated price of condensate and pentanes plus is lower than their market value, research into alternatives is hindered. Price deregulation would accelerate such research and preclude premature depletion of Canadian condensate and pentanes plus resources. Moreover, such a move could encourage capital investment in upgrading facilities either at conventional refineries or at stand-alone sites. Heavy oil upgrading in Canada would in turn create a significant number of jobs and investment opportunities, and contribute to oil self-sufficiency and the development of Canadian technology. The economics of heavy oil upgrading, however, will critically depend on the course of price differentials between light and heavy crudes.

If required, fiscal incentives for heavy oil projects should be in terms of concessions until project pay out and/or reduced royalty/tax levies, rather than direct subsidies or price guarantees. The arguments for incentives are strong, but fiscal regimes must be flexible enough to allow investors a reasonable rate of return which takes the inherent risks of their investment into account.

The possibility of building new or reversing existing pipelines between Chicago and either Wood River or Patoka, Illinois and the potential demand of that market for Canadian heavy crude oil should be investigated in detail. Developments in that area could open new and large marketing opportunities for Canadian heavy oil.

7.8 Suggestions for Further Work

Additional work is required to identify U.S. crude oil production by quality of crude and producing state. Data on the disposition of U.S. crude oil production by refinery and crude quality are also required. The benefits realised from this information would be significantly greater if the effect on refinery throughput and product slate could be determined for various groups of crude qualities. Analysis taking into account information from crude oil assays would also be useful should time and resources permit using data at such a disaggregated level.

Identifying the impact of changes in crude oil quality on pipeline throughput volumes, and the cost of reversing the direction of various pipelines are also prerequisites for a more detailed and definitive analysis of U.S. heavy crude oil markets, particularly those accessible by Canadian heavy crude oil.

Similar Canadian refinery and pipeline data would also be required for a more meaningful and conclusive analysis of Canadian heavy crude oil market potential in North America.

Footnotes

[1] An alternative way of approximating the market value of diluent under deregulation would be to take the Montreal price of Algerian condensate (\$239.63/m^3 as of August 1984) and "back it up" to Edmonton by deducting transportation and terminal charges (\$8.19/m^3). That value, \$231.44/m^3, could then be applied in the deblending calculations to obtain a new value of the producer's netback. Since the \$231.44 is lower than the NORP value for condensate last August (\$258.30), the netbacks are then somewhat higher, \$179.20 and \$148.77/m^3 for Lloydminster and Cold Lakes crudes, respectively.

Since there are no deliveries of Algerian condensate to Montreal (or to Western Canada), however, this example must be considered for illustration only, particularly in view of the fact that the posted Montreal price of Algerian condensate has been fluctuating monthly by as much as \$12/m^3.

[2] The present prime marketing function of the APMC in the area of heavy crude oil is to market diluent, not heavy crude oil, which is largely sold by the producers themselves. Also, while at present the Province of Alberta absorbs the administrative cost of operating the Commission, under deregulation, APMC could be required to earn a brokerage fee, which is currently in the neighbourhood of 31 cents per cubic metre.

[3] Amoco Canada Petroleum Company Ltd., "Submission to the National Energy Board, Energy Supply and Demand 1984-2005" (Calgary: Amoco Canada Petroleum Company Ltd., 1984), p. 14; Foster Research, *The Forecast Supply and Demand for Alberta Condensate for Blending with Heavy Crude Oil 1984-2000* (Calgary: Foster Research, 1984), p. 25; and Gulf Canada Limited, "Canadian Energy Supply and Demand 1983-2000: Submission to the National Energy Board in the Matter of the 1984 Energy Supply and Demand Update," February 1984, p. 50.

[4] Amoco Canada Petroleum Company Ltd., "Submission to the National Energy Board, Energy Supply and Demand 1984-2005," p. 4; and Imperial Oil Limited, "Submission to the National Energy Board: In the Matter of Canada's Long-Term Energy Supply and Demand," February 1984, p. 8.

[5] Foster Research, *The Forecast Supply and Demand for Alberta Condensate for Blending with Heavy Crude Oil 1984-2000*, pp. 25 and 28.

[6] Hycarb Engineering Ltd., *Canadian Heavy Crude Oil Market Analysis* (Calgary: Hycarb Engineering Ltd., 1984), p. 96.

[7] One of the largest American importers of Canadian heavy crude oil indicated that there does and will exist a tremendous demand for Canadian heavy crude oil subject to the resolution of the diluent supply problem. Obviously, no serious commitments, particularly to upgrading or refinery expansion geared to Canadian sources of supply, will be made until assurances that the required amounts of Canadian heavy crude oil can be consistently provided.

[8] Hycarb Engineering Ltd., *Canadian Heavy Crude Oil Market Analysis*, p. 13.

[9] Ibid., p. 105.

[10] Gulf Canada Limited, "Canadian Energy Supply and Demand 1983-2000: Submission to the National Energy Board in the Matter of the 1984 Energy Supply and Demand Update," February 1984; Imperial Oil Limited, "Submission to the National Energy Board: In the Matter of Canada's Long-Term Energy Supply and Demand," February 1984; and Texaco Canada Inc., "Submission to the National Energy Board: Update of Energy Supply and Demand 1982-1995," February 1984.

[11] "Tax Bait Lures $1.8 Billion Elk Point Flood," Enhanced Recovery Week, March 5, 1984, pp. 1-2. See also "Esso Quickens Cold Lake Development Pace", Enhanced Recovery Week, May 14, 1984, p. 2.

[12] Ibid., pp. 1-2. Elk Point crude oil is similar to Cold Lake crude oil.

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LIST OF ABBREVIATIONS

The following abbreviations have been used throughout this study and are defined as follows:

NA	not applicable
NR	not reported
-	zero
--	amount too small to be expressed
( )	negative value (when around a given figure)
Mb/d	thousand barrels per day
MMb/d	million barrels per day

PREFACE

This study was undertaken during 1984 and completed in January 1985. Most of the data assembly and the analysis, however, was completed during the period from June to September of 1984.

The Institute is grateful for helpful comments on an earlier draft of the study by a four-member Advisory Committee comprised of two representatives from the heavy oil industry and two specialists from federal and provincial energy departments.

Thanks are due to the various industry and government officials for time spent in valuable meetings and exchanges which helped to shape the study and to strengthen the analysis. The authors themselves, however, are solely responsible for the conclusions drawn, and for any errors or omissions which may remain.

The principal authors of this study were C. Slagorsky, A. Webster and J. Pasay. Considerable assistance was provided by S. Cain, G. Morrison, S. Poohkay, J. Rashid and S. Streifel. In addition, F. Christensen, B. Cox, and A. Crowley assisted in the collection of data; D. Peterson, in graphics preparation; J. Morrison, J. Stinn and S. Ingstrup, in typing the final document and the several drafts which preceded it.

APPENDIX A

HISTORICAL CRUDE OIL PRICE DIFFERENTIALS IN WORLD MARKETS

Appendix A

HISTORICAL CRUDE OIL PRICE DIFFERENTIALS IN WORLD MARKETS

A.1 Review of Historical Crude Oil Price Differentials

In this section, historical crude oil price differentials are examined. The main determinants of crude oil value are briefly discussed and relative crude values exhibited in the market place are reviewed. Finally, parity pricing in the world crude oil market and its impact on crude oil price differentials are discussed.

Crude oil is generally considered to be a "homogeneous" product. However, all crude oils are not of equal value. Supply considerations such as availability, logistics, and security of supply are important factors in crude pricing. Individual refiners also value crude based on its physical properties and yield of refined products, given the refinery's configuration and anticipated operating conditions. The relative value of the refined products obtained is determined by overall supply and demand conditions and the prevailing product pricing regime. Over time these factors will change and interact to affect crude differentials--the relative value of different quality crude oils.

Price differentials are not readily discernible from crude oil market data due to both the market complexities described above and data limitations. Official posted price data are the most abundant and readily accessible data available. Most crude oil transactions are made at official price levels, although contract terms and conditions vary, altering the effective price.

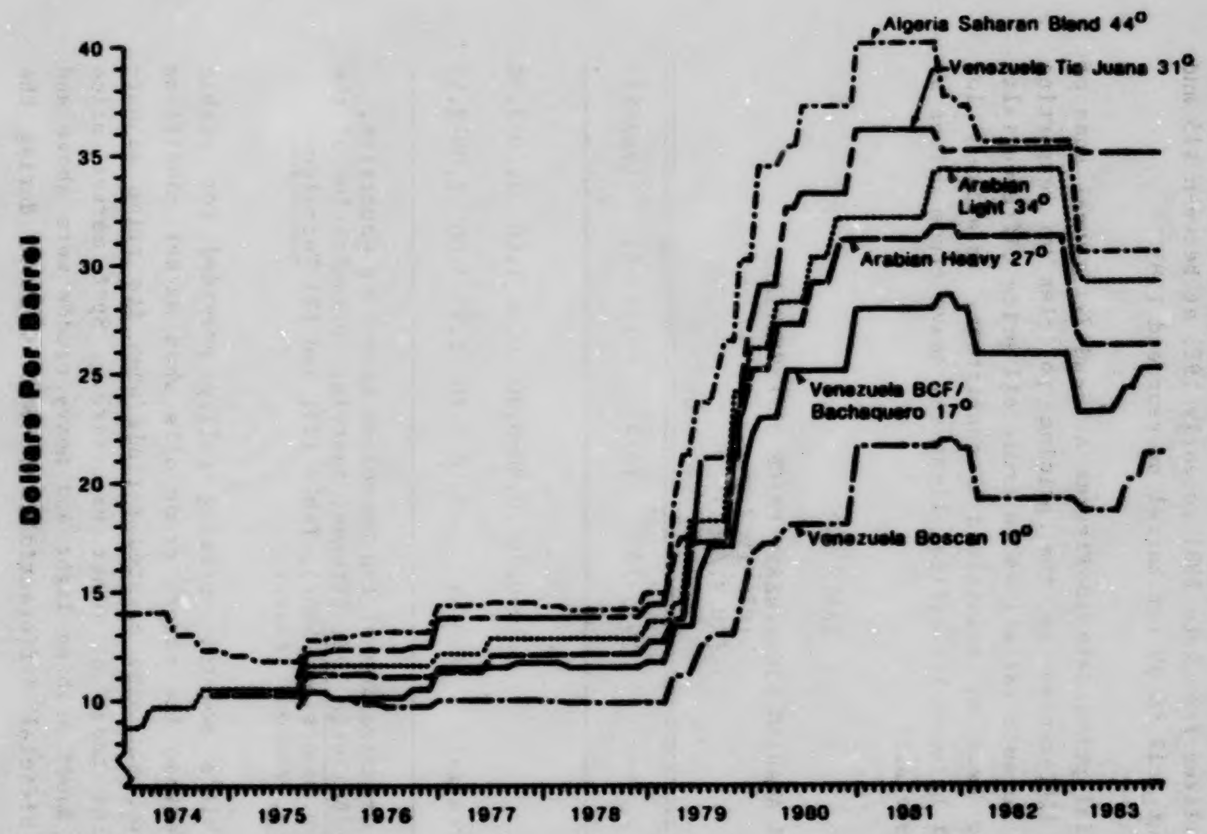
With the establishment of OPEC, official prices have sometimes been set by various countries to serve their political and economic goals[1] rather than according to current market forces, choosing short-term revenue gains and ignoring potential longer-term marketing problems. As a result, official price differentials between crudes from various regions are not always representative of the true difference in market value between various crudes.

Alternatively, spot market oil prices provide a more consistent basis for comparing the true market value of various crude oils. Spot market prices are responsive to the forces of supply and demand, product pricing, and refinery economics, and as such are good indicators of market trends. Spot market sales also represent the world oil and product markets' balancing mechanism. Thus, spot market prices more closely reflect the value of processing the "last" or marginal barrel rather than the average barrel of oil. On the other hand, the spot market itself has been evolving, with long-term product demand trends affecting world refinery configuration and utilization. Also, limited data are available on spot sales, complicating a detailed study of differentials on this basis. In particular, no spot market price data are available for extra heavy crudes traded internationally that are comparable to Canadian heavy crude exports. Saudi Arabian heavy crude oil at 27° API is almost a medium crude compared to some Canadian heavy crudes at 11° to 22° API. All of these factors require careful consideration when using spot market prices to examine differentials.

A.1.1 Historical Official Crude Oil Price Differentials

In the forties and fifties, the relative prices of gasoline and residual fuel oil (RFO) were stable such that a general rule of thumb in marketing crude oils was to increase the price of crude by 2 cents per barrel for an increase of 1° in API gravity.[2] In the sixties, gasoline demand continued to grow, putting increasing pressure on refiners to dispose of increasingly unwanted residuals. This was an era of "cheap" energy and increasing energy demand. The first major oil supply disruption and the ensuing large oil price increases began a new period of conservation, low energy demand growth, and changing product demands. In addition, price control shifted from the major oil companies to the individual exporting countries. Thus, the postembargo period is most relevant to the current and future marketplace in a discussion of crude oil price differentials.

The official price history of several key OPEC crude oils from 1974 to 1983 is summarized in Figures A.1 and 2.1. During this period, the f.o.b. price of the OPEC marker crude, Saudi Arabian light, rose in discrete steps from a low of $11.40 (U.S.) per barrel in 1974 to $14.50 by mid-1979. By the end of 1981 the price increased to $34 per barrel where it held until the first quarter of 1983 when the price dropped to its current level of $29 per barrel.[3]



SOURCE: CERI calculations based on Petroleum Intelligence Weekly, various issues, and OPEC Annual Statistical Bulletin, various issues.

FIGURE A.1: OFFICIAL PRICES FOR OPEC CRUDE OILS: 1974-1983

The official prices of other OPEC and non-OPEC crude oils varied widely relative to the Saudi Arabian marker crude price (see Figure 2.1). For example, the price spread between extra light/sweet Algerian Saharan and extra heavy/sour Venezuelan Boscan grew from $3 to $4 per barrel in 1976 and 1977, to reach as high as $19 in 1980. The differential stabilized from late 1981 to early 1983 at between $15 and $16 per barrel, but fell to $9 per barrel by year end 1983.

The official price data in Figures A.1 and 2.1 reveal some of the significant differences in the pricing policies of exporting nations which led to such variations in crude oil price differentials. Saudi Arabia, for example, maintained a consistent, relatively low price differential between its offical light and heavy crude prices as shown below in Table A.1:

TABLE A.1

SAUDI ARABIAN LIGHT/HEAVY PRICE DIFFERENTIALS
1976-1983
($U.S./bbl)

	1976-78	1979	1980-81	1982-83
Official Price Differentials	0.40-0.70	0.80-0.90	0.80-1.00	2.50-3.00
Spot Market Differentials	NR	3.10-3.70	1.90-4.00	2.00-2.50

SOURCES: (1) Organization of the Petroleum Exporting Countries, Annual Statistical Bulletin 1981 (Vienna, Austria: Organization of the Petroleum Exporting Countries, 1982), Table 123; and (2) Petroleum Intelligence Weekly, various issues.

Saudi Arabia's moderate pricing policy provided for stable relative prices between its export crude oils when market conditions suggested otherwise, but also created periods when its price adjustments lagged behind those of other exporters. Spot market price differentials for Saudi Arabian light and heavy crudes were above and below prevailing official differentials at various times during the same period.

In contrast to Saudi Arabian policy, Iranian policy resulted in its heavy oil prices exceeding the superior quality Saudi Arabian light price by as much as $6 per barrel during 1979 and 1980. This situation was reversed in 1982 when Iranian heavy crude oil was priced close to $6 per barrel less than Saudi Arabian light, and $4.40 per barrel less than equivalent quality Saudi Arabian medium.

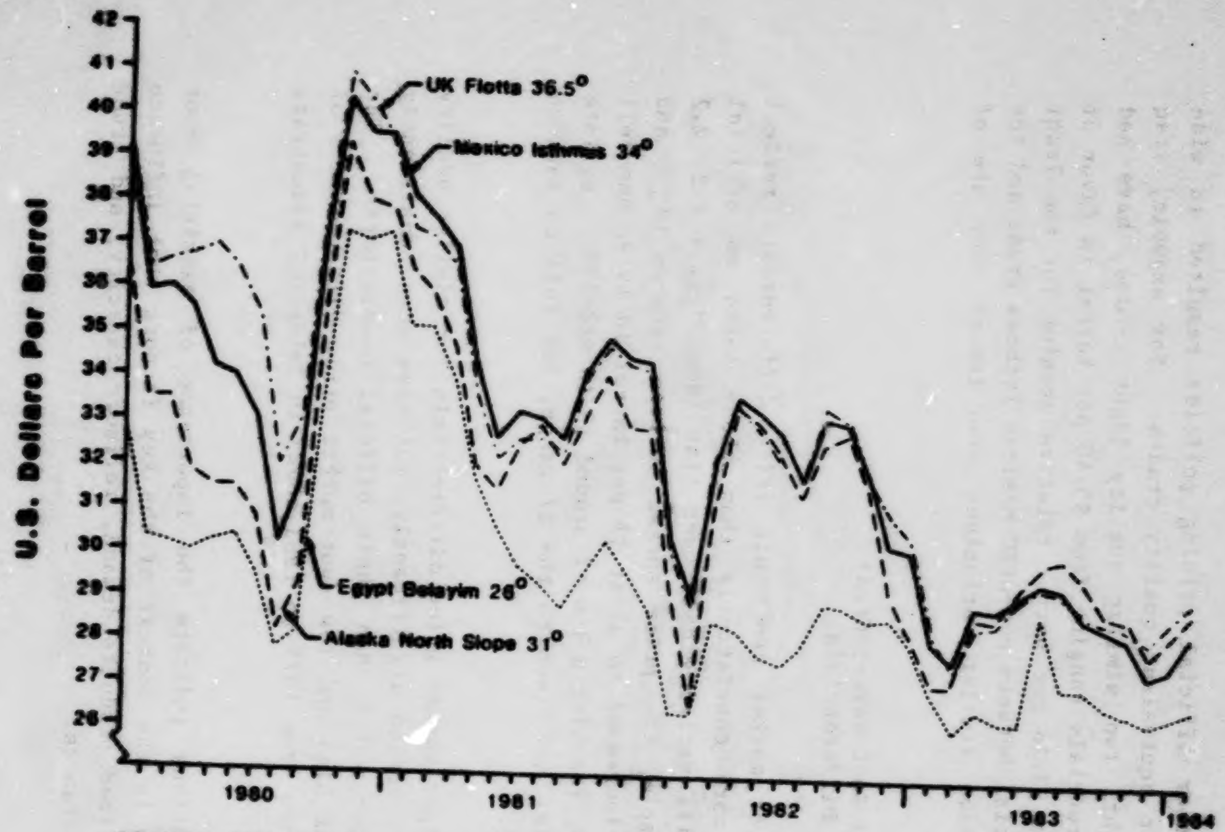
Similarly, other official pricing policies resulted in wide price differences for equivalent quality crudes. For example, Iraq Basrah and Iran Light, two similar quality light crudes, have had official price differentials ranging from $5.40 per barrel in favor of the Iranian crude, to $3.26 per barrel relative premium for the Iraqi crude. The differential between non-OPEC Mexican Isthmus crude and the Iraqi crude have shown similar variations even though they are of similar quality.

A.1.2 Historical Spot Market Crude Oil Price Differentials

Published spot market crude oil price differentials reflect true market value more consistently than those based on official prices, but have still varied widely over time (see Figures A.2, 2.2 and 2.3). For example, the price spread between Saharan Light and Saudi Arabian Heavy increased to about $8 per barrel in 1979, but fell gradually thereafter, reaching a low of around $3 in mid-1980. By late 1981, the differential had risen to the $7 range, but fell to between $3.50 and $4 by 1983.

Historical spot market price differentials for similar quality crude oils have also varied significantly, but have more consistently reflected true market value than their official counterparts. The ranges of historical high and low spot market price differentials of similar quality crudes from 1979 to 1983 shown in Table A.2 illustrate this variation.

These variations indicate the importance of examining spot price differentials in the context of the key factors that influence them, including refined products demand, refinery capacity, and crude oil supply/demand balances.



SOURCE: CERI calculations based on Petroleum Intelligence Weekly, various issues, and OPEC Annual Statistical Bulletin, various issues.

FIGURE A.2: SPOT MARKET PRICES FOR NON-OPEC CRUDE OILS: 1980–1984

TABLE A.2

RANGE OF HISTORICAL SPOT MARKET PRICE DIFFERENTIALS
1979-1983
($U.S./bbl)

Type (API/Sulphur)	Sample Crudes	Price Differential	
		High	Low
Medium/Sour	Saudi Arabian Medium to Iran Heavy	0.50	(0.50)
Heavy/Sour	Saudi Arabian Heavy to Egypt Belayim	3.45	(0.50)
Heavy/Medium Sour	Ecuador Oriente to Alaska North Slope	2.60	(0.95)

SOURCE: Petroleum Intelligence Weekly, various issues.

A.2 Historical Factors Affecting Differentials

A.2.1 Product Demand

The significant increase in crude oil price differentials during the 1975 to 1979 period was partially the result of strong light product demand growth (see Figures A.3 to A.5). Gasoline and middle distillates demand increased rapidly between 1975 and 1979, particularly in Western Europe and Japan with 3 to 5 percent average annual growth rates for those products.[4] U.S. average annual gasoline demand growth was only about 2 percent, but represented significant additional volume requirements. At the same time, residual fuel oil (RFO) demand was constant or falling in most countries. Japanese and European RFO growth was virtually zero, while U.S. RFO consumption grew at an average rate of 3.5 percent per annum.

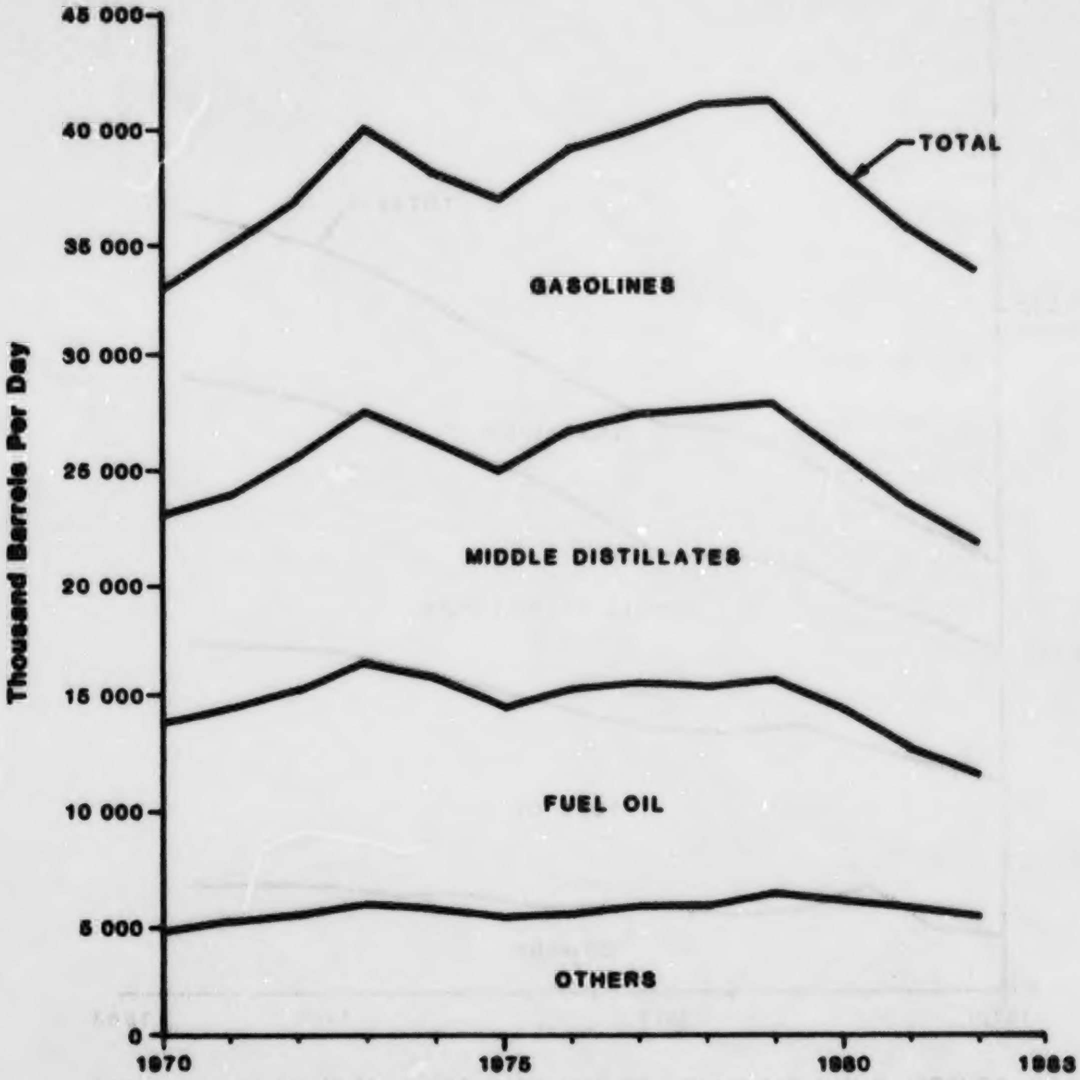
This increased demand for light products increased demand for light crude oils with light product yields. Competition for light crudes and surplus RFO both tended to widen the crude price differentials between light and heavy crude oils.

Following the 1979 to 1980 crude oil price increases, refined products demand declined from 1980 to 1983 at an average annual rate of about 3 percent in non-Communist countries, and 4 to 5 percent in the U.S., Japan, and Western Europe. Fuel oil demand suffered the sharpest declines, falling from 10 to 17 percent in these three countries. However, even though fuel oil demand was declining relatively faster than light products demand, crude oil price differentials were narrowing since light crude oil supply was increasing relative to heavy crude oil supply.

A.2.2 Refinery Utilization/Capacity

Another key factor determining the historical pattern of crude oil price differentials was the prevailing refinery capacity and utilization patterns, especially in the European and U.S. markets.

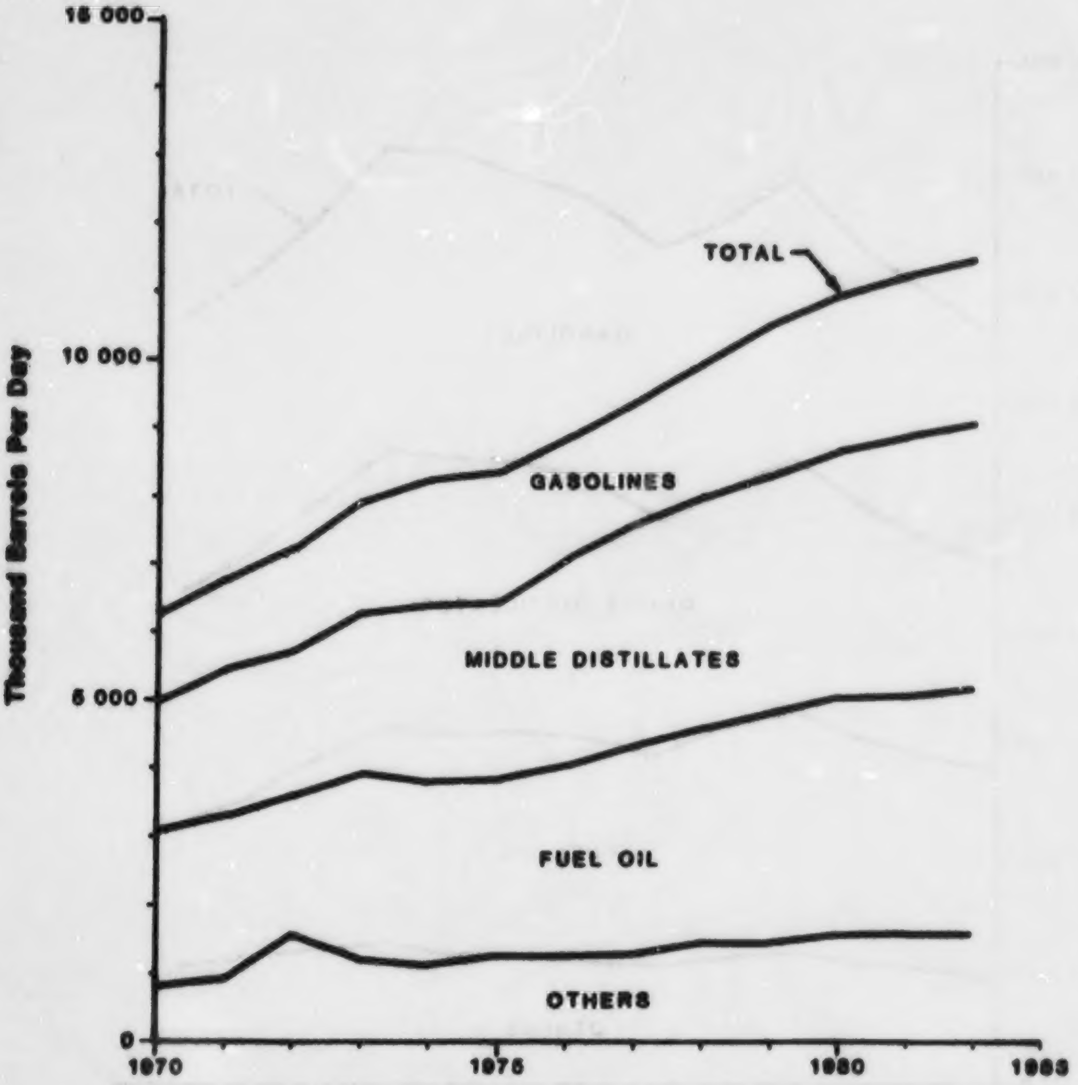
The U.S. refining industry has always had higher conversion capabilities (light products yield) compared to European and other world refining centres due to higher levels of gasoline demand. From 1975 to 1979, refinery capacity increased some 17 percent but total product demand increased only 13 percent.[5] High utilization rates of



SOURCE: British Petroleum , BP Statistical Review of World Energy , 1984

NOTE: Includes Bunkers. OECD includes Australasia, Canada, Japan, the United States, and Western Europe.

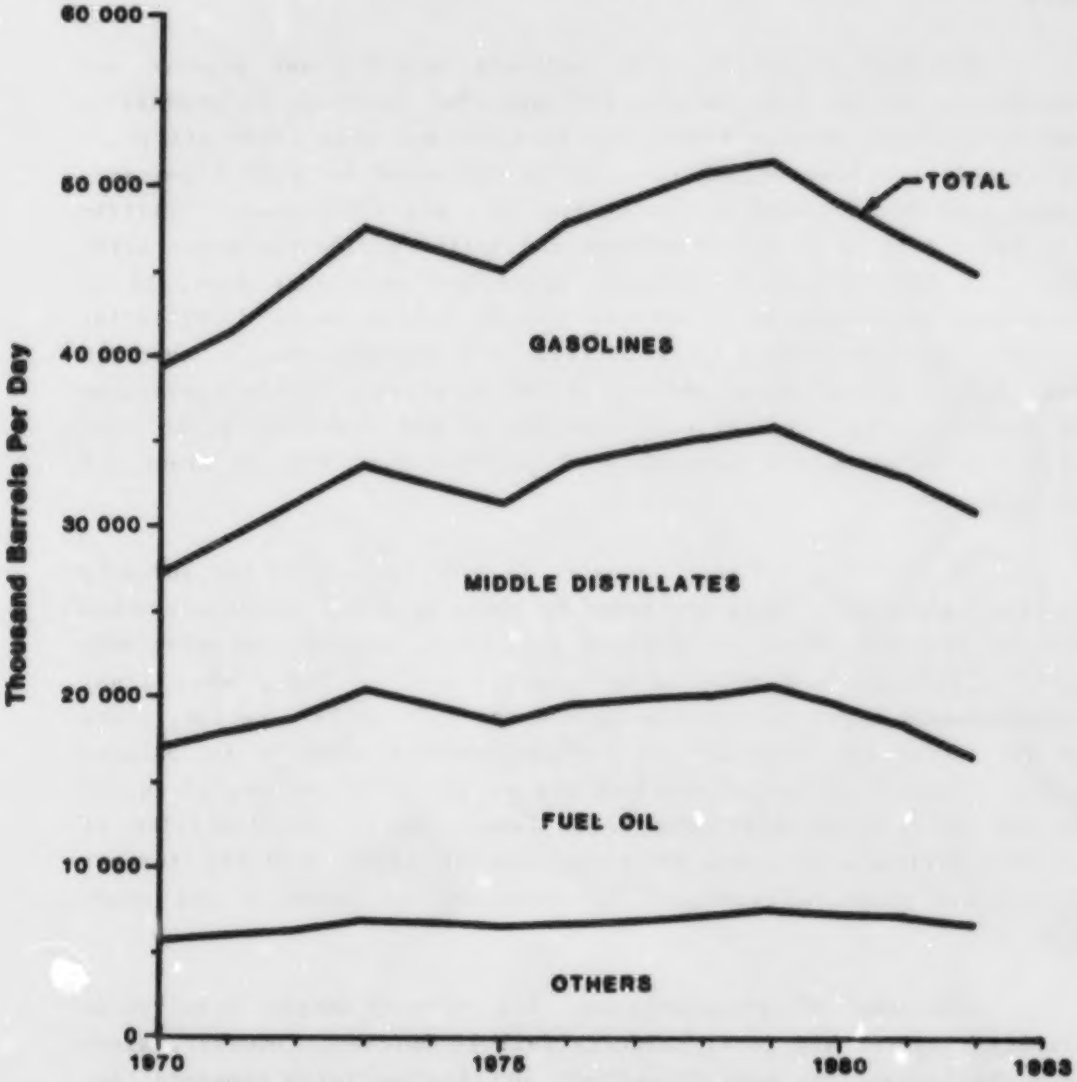
FIGURE A.3: OECD MAIN PRODUCT CONSUMPTION: 1970-1983



SOURCE: British Petroleum , BP Statistical Review of World Energy , 1984

NOTE: Includes Bunkers. NON-OECD excludes China, Eastern Europe, and USSR.

FIGURE A.4: NON-OECD MAIN PRODUCT CONSUMPTION: 1970-1983



SOURCE: British Petroleum , BP Statistical Review of World Energy , 1984

NOTE: Includes Bunkers. World excludes China, Eastern Europe, and USSR.

FIGURE A.5: WORLD MAIN PRODUCT CONSUMPTION: 1970-1983

80 to 90 percent limited refiners' flexibility to reduce residual fuel oil production and still maintain high light product output. Consequently, RFO output levels were relatively high, which lowered RFO and, subsequently, heavy crude oil prices and widened crude oil differentials.

New high conversion U.S. refinery capacity was planned and commissioned in the U.S. between 1980 and 1981 based on the prevailing demand patterns, excellent refinery margins, and wide crude oil price differentials. However, while capacity increased by some 7 percent, demand fell dramatically following the 1979 price increase. Utilization rates fell to 65 to 70 percent and refinery closures began after 1981. In 1982 alone, 46 refinery operations were shut down, 26 of which were less than 10 years old and 24 having crude distillation capacity of less than 10,000 barrels per calendar day.[6] Nevertheless, since many of these refineries had relatively simple operations and low capacity, the average complexity and flexibility of U.S. refineries to produce a wide range of products from a given crude oil stream increased.

The European refining industry is more typical of the industry structure worldwide, being dominated by hydro skimming operations which tend to have high rates of residual fuel production due to relatively higher distillate and RFO demand than the U.S. Thus, when light product demand began to increase during the 1975 to 1979 period, there was an increasing reliance on refined product imports to balance demand. Utilization rates remained low at around 60 percent of capacity and no capacity additions took place. Thus, the inability of European refiners to increase production of light products further widened the price differential for both refined products and crude oils.

After the 1979 price increase, low refinery margins resulted in refinery closures and total capacity fell 18 percent. However, since demand had dropped by some 28 percent, utilization rates remained low. Nevertheless, refinery closures and new refinery investments gave European refineries additional flexibility in handling heavier crudes such that light product yields began increasing in total for the region.

A.2.3 Crude Oil Supply/Demand

Crude oil supply and demand movements have also affected historical differentials. Crude oil price differentials widened significantly between 1975 and 1979 partially due to higher growth in oil demand relative to supply, especially for light crude oil. Primary energy demand increased almost 4 percent per annum during this period, with oil accounting for over 40 percent of the total growth.[7] OPEC crude oil production was at 80 to 90 percent of total capacity to meet import demands. The U.S. in particular was becoming increasingly dependent on oil imports, which rose from 1.3 trillion barrels in 1974 to 2.4 trillion barrels in 1979.[8] OPEC supplied about 60 percent of U.S. import needs from 1975 to 1979, which accounted for 15 to 20 percent of total domestic consumption of crude oil.

Given the high crude oil demand levels, world oil production was close to capacity with little flexibility to vary light oil supply levels to meet increasing demand for light products without new capacity additions. Consequently, the price of light crude oils rose relative to heavy crude oil during the 1976 to 1979 period.

Following the 1979 Iranian oil supply disruption and the subsequent sharp oil price increases, world oil demand declined significantly due to the combined impacts of recession, conservation, and fuel switching. OPEC crude oil production was at 60 to 65 percent of capacity, with some OPEC members cutting higher value light crude oil production less than heavy crude oil production. At the same time, however, United Kingdom production of light crude oils was increasing and displacing light African crudes, particularly in the European market. The increased competition for market share by light crude oils narrowed crude oil price differentials.

Increasing competition for market share caused OPEC to lower official oil prices in 1983 and introduce a production quota system to keep prices from dropping further. This quota system imposes artificial constraints on the supply of both light and heavy crude oils which precludes OPEC's ability to set crude oil price differentials that accurately reflect true market values.

A.3 Parity Pricing

At the present time, Western Hemisphere sour crude oils are priced competitively with similar Middle Eastern crude oils in Europe.

This is primarily because Western Hemisphere heavy crude oil demand can be met without Middle Eastern imports. Crude oil price parity with Middle Eastern crude oils has been projected to be reestablished on the U.S. Gulf Coast by 1985. However, recent projections by the U.S. Department of Energy suggest that U.S. imports will rise slowly, such that Gulf Coast parity pricing may not occur until the late 1990s.

Exports of African crude oil have been increasingly directed to European markets primarily as a result of a 40 percent decline in U.S. imports from 1977 to 1983.[9] African crude oil exports to the U.S. declined from 2.3 million barrels per day in 1978 or 42 percent of the total export volume, to some 0.8 million barrels per day in 1983 representing 21 percent of total exports (see Table A.3). In contrast, African crude oil exports to Europe have increased from 47 percent to 67 percent of the total over the same period, despite a net decline in absolute terms of 5 percent or 120,000 barrels per day.

Western Hemisphere crudes have also been increasingly marketed in Europe. For example, Venezuelan crude oil exports to OECD Europe as a percentage of total exports to OECD countries have increased from 20 to 53 percent from 1978 to 1983, while total volumes more than doubled over the same period. Similarly, Mexican exports to OECD Europe have increased from 6,000 to 380,000 barrels per day from 1978 to 1983. These volumes represent an increase from 2 to 28 percent of total Mexican exports to OECD countries.

Middle Eastern, African and Latin American crude oil exports to Europe have been hampered by significant increases in North Sea production. North Sea exports to Western Europe increased over 300 percent between 1977 and 1983; from 430,000 to some 1.4 million barrels per day (see Table A.4). However, future anticipated declines in North Sea production could reopen the European market to other exporting countries to a greater extent.

In order for future crude oil parity pricing to return to the U.S. Gulf Coast, U.S. import demand must become stronger to relieve some pressure on exporting nations to market crude oil in Europe. U.S. crude oil imports are projected to increase by 3 percent per annum, from 5.2 million barrels per day in 1984 to 7.2 million barrels per day by 1995 (see Table A.5). OECD European import levels are forecast to rise more slowly at about 1 percent annually from 8.1 million barrels per day in 1984 to 9.0 million barrels per day in 1995. On a percentage basis, U.S. crude oil import requirements are expected to increase

TABLE A.3

DISPOSITION OF AFRICAN, MEXICAN, MIDDLE EASTERN, AND VENEZUELAN CRUDE OIL EXPORTS
1978-1983

Year	OECD						Other World		Total Exports[c]
	Europe		U.S.		Other OECD[b]				
	(Mb/d)	(%)[a]	(Mb/d)	(%)[a]	(Mb/d)	(%)[a]	(Mb/d)	(%)	(Mb/d)
Africa									
1978	2 550	46.5	2 285	41.7	10	0.2	650	11.9	5 485
1979	2 880	47.4	2 540	41.8	35	0.6	615	10.1	6 070
1980	2 430	45.9	2 000	37.7	80	1.5	785	14.8	5 295
1981	2 010	51.5	1 375	35.2	125	3.2	395	10.1	3 905
1982	2 200	60.4	850	23.3	65	1.8	530	14.5	3 645
1983	2 430	67.4	755	20.9	85	2.4	335	9.3	3 605
Mexico									
1978	6	1.9	307	97.2	3	0.9	NR	NA	316
1979	42	8.6	446	91.4	-	-	NR	NA	488
1980	138	19.7	531	75.7	32	4.6	NR	NA	701
1981	271	30.8	486	55.3	122	13.9	NR	NA	879
1982	341	28.0	726	59.6	152	12.5	NR	NA	1 219
1983[d]	380	27.6	807	58.6	190	13.8	NR	NA	1 377
Middle East									
1978	8 685	44.0	2 300	11.7	4 535	23.0	4 210	21.3	19 730
1979	8 685	42.5	2 115	10.3	4 700	23.0	4 435	21.7	20 435
1980	7 275	41.5	1 555	8.9	4 080	23.3	4 600	26.3	17 510
1981	5 750	39.4	1 255	8.6	3 395	23.2	4 602	31.5	14 605
1982	4 625	39.7	770	6.6	3 005	25.8	3 260	28.0	11 660
1983	3 415	33.0	575	5.6	2 930	28.3	3 435	33.2	10 355
Venezuela									
1978	116	19.6	257	43.5	218	36.9	NR	NA	591
1979	166	22.5	365	49.4	208	28.1	NR	NA	739
1980	230	36.9	193	31.0	200	32.1	NR	NA	623
1981	285	43.0	193	29.1	185	27.9	NR	NA	663
1982	194	39.8	161	33.0	133	27.3	NR	NA	488
1983[d]	258	53.3	135	27.9	91	18.8	NR	NA	484

SOURCES: (1) The British Petroleum Company, BP Statistical Review of World Energy, 1972 to 1983; and (2) Energy Economic Research Limited, World Oil Trade, December 1983, Tables 32 to 38.

[a] Percentages for Mexico and Venezuela based on Total Exports to OECD countries only.
[b] Includes Australasia, Canada, and Japan.
[c] Figures may not add due to rounding. Total Exports for Mexico and Venezuela include only exports to OECD countries.
[d] Based on the first half of 1983 only.

TABLE A.4

CRUDE OIL IMPORTS BY OECD EUROPEAN COUNTRIES
1977-1983

Source	1977	1978	1979	1980	1981	1982	1983[a]
Volumes (Mb/d)							
Middle East	8,581.8	8,111.9	7,921.8	6,650.2	5,312.1	3,953.6	2,806.3
Africa	2,246.0	2,380.7	2,764.7	2,403.4	1,844.4	2,070.6	2,096.1
Indo-China	19.8	26.7	30.3	10.2	11.5	14.3	9.1
Latin America	103.6	122.0	207.0	370.3	562.5	543.3	657.4
North Sea	430.2	525.5	836.5	862.9	911.2	1,044.6	1,364.1
U.S.S.R.	611.8	631.9	621.0	537.0	510.1	598.2	594.8
Other	177.4	131.9	212.7	143.0	157.5	210.0	159.4
TOTAL	12,170.6	11,930.6	12,594.0	10,977.0	9.309.3	8,434.6	7,687.2
Distribution (%)							
Middle East	70.5	68.0	62.9	60.6	57.1	46.9	36.5
Africa	18.5	20.0	22.0	21.9	19.8	24.5	27.3
Indo-China	0.2	0.2	0.2	0.1	0.1	0.2	0.1
Latin America	0.9	1.0	1.6	3.4	6.0	6.4	8.6
North Sea	3.5	4.4	6.6	7.9	9.8	12.4	17.7
U.S.S.R.	5.0	5.3	4.9	4.9	5.5	7.1	7.7
Other	1.5	1.0	1.7	1.3	1.7	2.5	2.1
TOTAL	100.0	100.0	100.0	100.0	100.0	100.0	100.0

SOURCE: Energy Economic Research Limited, World Oil Trade, December 1983, Tables 32 to 38.

[a] Based on the first half of 1983 only.

TABLE A.5

WORLD CRUDE OIL IMPORTS BY IMPORTING COUNTRY[a]

1980-1995
(MMb/d)

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995
Production												
OECD Europe	2.6	2.9	3.4	3.9	4.0	3.9	3.8	3.7	3.6	3.5	3.4	3.6
United States	10.8	10.7	10.8	10.8	10.8	10.9	10.9	10.8	10.9	11.0	10.9	10.5
Other Countries	6.3	6.9	7.6	7.9	8.4	8.8	9.2	9.5	9.9	10.3	10.7	12.7
Total	19.7	20.5	21.8	22.6	23.2	23.6	23.9	24.0	24.4	24.8	25.0	26.8
Consumption												
OECD Europe	13.5	12.5	12.2	11.8	12.1	12.5	12.9	13.2	13.3	13.2	13.1	12.6
United States[b]	17.5	16.5	15.6	15.5	16.0	16.1	16.4	16.7	16.8	16.9	16.9	17.7
Other Countries	14.0	13.7	13.5	13.3	13.4	13.6	14.1	14.6	14.8	14.9	15.0	16.2
Total	45.0	42.7	41.3	40.6	41.5	42.2	43.4	44.5	44.9	45.0	45.0	46.5
Net Imports[a]												
OECD Europe	10.9	9.6	8.8	7.9	8.1	8.6	9.1	9.5	9.7	9.7	9.7	9.0
United States	6.7	5.8	4.8	4.7	5.2	5.2	5.5	5.9	5.9	5.9	6.0	7.2
Other Countries	7.7	6.8	5.9	5.4	5.0	4.8	4.9	5.1	4.9	4.6	4.3	3.5
Total	25.3	22.2	19.5	18.0	18.3	18.6	19.5	20.5	20.5	20.2	20.0	19.7

SOURCE: United States Energy Information Administration, Annual Energy Outlook 1983 (Washington, D.C.: U.S. Government Printing Office, 1984), Table 5, p. 20.

[a] Imports estimated as domestic production less consumption. Crude oil includes crude oil, natural gas liquids, refinery gains, hydrogen, and other hydrocarbons.

[b] Includes Puerto Rico and the Virgin Islands.

only marginally from 28 to 30 percent of total world net imports from 1984 to 1990, but increase more significantly to 37 percent of the world total by 1995. On the other hand, the percentage of OECD European import requirements increase from 44 percent in 1984 to 49 percent in 1990, then decline to 46 percent in 1995. Based on these projections, crude oil parity pricing is not likely to move to the U.S. Gulf Coast from Europe much before 1990.

The above analysis has the following implications on world crude oil price differentials. Marginal increases in crude oil demand and increasing crude oil exports from Africa and Latin America at the expense of Middle Eastern crude oils imply that OPEC productive capacity could be underutilized into the 1990s, and that a surplus supply of light crude oil will exist in the marketplace until U.S. import demand levels increase sufficiently. Consequently, crude oil price differentials may remain at current relatively narrow levels for several years regardless of heavy crude oil supply and upgrading capacity developments.

A.4 Summary

Historical official and spot market crude oil price differentials have both varied significantly over time. Nevertheless, the latter more accurately reflect true market value for crude oils since spot market prices are responsive to the forces of supply and demand.

Refined products demand, refinery configuration and utilization, and crude oil supply and demand are the three primary factors that have affected historical crude oil price differentials. The interaction between these factors caused crude oil price differentials to widen from 1975 to 1979 and narrow thereafter. However, no clear pattern emerges to provide a methodology for forecasting future crude oil price differentials, even though the same factors are expected to be of major significance to future differentials.

Footnotes

[1] "How Price Differentials Affect Refinery Upgrading," Petroleum Intelligence Weekly, May 7, 1984, p. 7.

[2] It is interesting to note that the New York futures market is currently using a similar methodology to set its prices. See "Price Differentials a Thorny Issue for London Oil Futures," Petroleum Intelligence Weekly, October 31, 1983, pp. 7-8.

[3] "Updated Price Scorecard for Key World Crudes," Petroleum Intelligence Weekly, October 29, 1984, Special Supplement, p. 1.

[4] The British Petroleum Company, BP Statistical Review of World Energy, June 1984, p. 10.

[5] E. L. Peer et al., Trends in Refinery Capacity and Utilization (Washington, D.C.: United States Department of Energy, 1980), Table 4, p. 16; and The British Petroleum Company, BP Statistical Review of World Energy, June 1984, p. 10.

[6] National Petroleum Refiners Association, U.S. Refining Capacity: 1984 (Washington, D.C.: National Petroleum Refiners Association, 1984), Table 12, p. 33-35.

[7] The British Petroleum Company, BP Statistical Review of World Energy, June 1984, pp. 7 and 28.

[8] American Petroleum Institute, Basic Petroleum Data Book, Volume IX, Number 3, September 1984 (Washington, D.C.: American Petroleum Institute, 1984), Section IX, Table 4a to 4c, and Section VII, Table 2a.

[9] The British Petroleum Company, BP Statistical Review of World Energy, June 1984, p. 16.

APPENDIX B

HISTORICAL CRUDE OIL DATA TABLES

TABLE B.1

CANADIAN CRUDE OIL PRODUCTION[a]
1973-1983
(10^6m^3)

	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1983 % of Total Group Production	1983 % of Total Cdn. Production
Alberta													
Light	79.5	75.7	64.3	57.0	55.9	55.4	63.6	58.4	52.2	50.1	50.4	76.5	64.2
Medium	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR	NA	NA
Heavy	3.5	3.4	3.2	3.7	4.6	4.7	4.9	4.6	4.8	4.3	4.8	7.3	6.1
Total	83.0	79.1	67.5	60.7	60.5	60.1	68.5	63.0	57.0	54.4	55.2	100.0	70.3
Synthetic	2.9	2.7	2.5	2.8	2.6	3.2	5.3	7.4	6.5	7.0	9.2	13.9	11.7
Experimental	0.1	0.1	0.2	0.4	0.5	0.4	0.6	0.5	0.8	1.2	1.5	2.3	2.0
Total	86.0	81.9	70.2	63.9	63.6	63.7	74.4	70.9	64.3	62.6	65.9	100.0	84.0
Saskatchewan													
Light	4.3	4.0	3.5	3.2	3.1	2.9	2.7	2.8	1.9	2.2	3.0	31.6	3.8
Medium	7.1	5.6	3.8	4.0	4.8	4.7	4.4	4.2	2.9	3.2	3.3	34.7	4.2
Heavy	2.2	2.1	2.0	1.6	1.9	2.0	2.2	2.4	2.6	2.7	3.2	33.7	4.1
Total	13.6	11.7	9.3	8.8	9.8	9.6	9.3	9.4	7.4	8.1	9.5	100.0	12.1
Canada													
Light	88.3	83.7	71.1	63.5	62.1	61.1	69.3	63.9	56.9	55.2	56.5	72.0	72.0
Medium	7.1	5.6	3.8	4.0	4.8	4.7	4.4	4.2	2.9	3.2	3.3	4.2	4.2
Heavy	5.7	5.5	5.3	5.3	6.4	6.6	7.2	7.0	7.4	7.0	8.0	10.2	10.2
Total	101.1	94.8	80.2	72.8	73.3	72.4	80.9	75.1	67.2	65.4	67.8	86.4	86.4
Synthetic	2.9	2.7	2.5	2.8	2.6	3.2	5.3	7.4	6.5	7.0	9.2	11.7	11.7
Experimental	0.1	0.1	0.2	0.4	0.5	0.4	0.6	0.6	0.8	1.2	1.5	1.9	1.9
TOTAL	104.1	97.6	82.9	76.0	76.4	76.0	86.7	83.1	73.5	73.6	78.5	100.0	100.0

SOURCE: Energy, Mines and Resources Canada, Energy Statistics Handbook, as updated to July 1984 (Ottawa: Energy, Mines and Resources Canada, Energy Statistics Division, 1983), pp. 3.9-3.11.

[a] According to the Alberta Energy Resources Conservation Board, Alberta crude is categorized as follows: heavy is <25° API, light is ≥25° API. According to the Saskatchewan Department of Energy and Mines, Saskatchewan crude is categorized as follows: heavy is ≤17° API, medium is ≤29° API, and light is >29° API.

TABLE B.2

CANADIAN CRUDE OIL INITIAL ESTABLISHED AND
REMAINING ESTABLISHED RECOVERABLE RESERVES
1981-1983
($10^6 m^3$)

	Initial Established[a] Recoverable Reserves			1983 % of Total Group	Remaining Established[a] Recoverable Reserves			1983 % of Total Group	1983 % of Canadian Total
	1981	1982	1983		1981	1982	1983		
Alberta									
Light	1 831.2	1 845.2	1 871.5	81.3	661.8	628.0	607.2	69.2	49.2
Medium	39.0	37.5	40.7	1.8	15.7	14.4	16.1	1.8	1.3
Heavy	97.5	102.1	110.1	4.8	41.4	40.1	41.9	4.7	3.4
Total	1 967.6	1 984.8	2 022.4	87.9	718.8	682.5	665.3	75.8	53.9
Synthetic[b]	268.1	268.1	268.1	11.7	222.1	215.1	205.9	23.5	16.7
Bitumen[c]	NR	11.2	11.5	0.5	NR	7.1	6.3	0.7	0.5
Total	2 235.7	2 264.1	2 302.0	100.0	940.9	904.7	877.5	100.0	71.1
Saskatchewan									
Light	131.6	129.6	133.9	32.5	28.3	24.4	24.9	21.8	2.0
Medium	120.6	121.4	121.5	29.5	36.8	35.6	34.2	30.0	2.8
Heavy	145.8	146.9	157.1	38.1	52.0	49.8	55.2	48.2	4.5
Total	398.0	397.9	412.5	100.0	117.1	109.7	114.3	100.0	9.3
Canada									
Light	2 279.1	2 295.4	2 343.4	76.8	917.7	881.3	875.2	70.9	70.9
Medium	159.6	159.0	162.2	5.3	52.4	50.0	50.4	4.1	4.1
Heavy	243.3	249.0	267.3	8.8	93.4	89.8	97.1	7.9	7.9
Total[d]	2 681.9	2 703.3	2 772.8	90.8	1 063.6	1 021.1	1 022.7	82.9	82.9
Synthetic[b]	268.1	268.1	268.1	8.8	222.1	215.1	205.9	16.7	16.7
Bitumen[c]	NR	11.2	11.5	0.4	NR	7.1	6.3	0.5	0.5
TOTAL	2 950.0	2 982.6	3 052.4	100.0	1 285.7	1 243.3	1 234.9	100.0	100.0

SOURCE: Canadian Petroleum Association, CPA Statistical Handbook, as updated to 1983 (Calgary: Canadian Petroleum Association, 1983), Section II, Tables 15A, 16, and 33.

[a] Established reserves are those reserves recoverable under current technology and present and anticipated economic conditions, plus those recoverable reserves thought to exist with reasonable certainty. Initial established reserves are established reserves prior to the deduction of any production. Remaining established reserves are initial established reserves less cumulative production.

[b] Includes established developed non-conventional reserves based on the rated output capacity over a 25-year estimated economic lifetime period of existing oil sands plants and plants scheduled to start production within three years. According to the CPA "these estimates in no way detract from published estimates of approximately 50 billion cubic metres which are estimated to be recovered from the Athabasca-type oil sands by mining or in-situ processes" (Section II Report).

[c] Includes established developed non-conventional reserves recoverable by existing experimental/demonstration projects calculated on the basis of demonstrated producibility and estimated life (in years) of the project.

[d] Canadian total includes 175 million cubic metres of eastcoast offshore light crude reserves.

TABLE B.3

U.S. CRUDE OIL PRODUCTION AND REMAINING RECOVERABLE RESERVES[a]
1973–1982
($10^6 m^3$)

	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1973 % of Total U.S. Production	1982 % of Total U.S. Production
Production:[b]												
PADD I	6.2	6.9	7.7	8.1	8.4	8.5	8.5	7.8	6.8	5.4	1.2	1.1
PADD II	56.2	53.2	51.2	52.1	51.7	50.7	50.5	53.8	56.5	59.2	10.5	11.8
PADD III	367.5	346.2	324.8	312.6	297.1	281.6	264.2	253.3	244.6	242.7	68.8	48.4
PADD IV	39.1	40.0	39.6	38.2	38.4	37.5	35.3	34.0	34.6	32.1	7.3	6.4
PADD V	65.0	62.7	62.4	62.0	82.6	126.7	137.5	150.9	154.7	162.4	12.2	32.4
TOTAL U.S.	534.0	508.9	485.7	472.9	476.2	505.0	496.0	500.0	497.2	501.9	100.0	100.0
Remaining Recoverable Reserves:[c]												
PADD I	42.0	63.0	56.0	53.9	47.0	40.7	33.2	31.6	27.2	28.9	0.7	0.6
PADD II	365.0	358.3	354.2	351.2	339.5	339.0	328.9	316.7	336.7	338.2	6.5	7.6
PADD III	2 770.6	2 589.8	2 366.2	2 161.2	1 972.1	1 809.9	1 910.5	1 886.7	1 909.4	1 795.1	49.4	40.5
PADD IV	271.1	262.4	242.6	225.0	221.2	206.4	215.1	236.6	216.7	224.8	4.8	5.1
PADD V	2 162.3	2 170.4	2 175.7	2 126.5	2 106.3	2 022.1	2 248.1	2 260.9	2 181.9	2 036.8	38.5	46.0
Miscellaneous	1.2	1.3	1.4	1.5	1.8	2.3	3.5	6.0	6.4	5.3	—	0.1
TOTAL U.S.	5 612.2	5 445.3	5 196.0	4 919.4	4 688.0	4 420.4	4 739.4	4 738.6	4 678.4	4 429.1	100.0	100.0

SOURCE: De Golyer and MacNaughton, Twentieth Century Petroleum Statistics 1983 (Dallas, Texas: De Golyer and MacNaughton, 1983), pp. 19–26.

[a] 1973 to 1978 reserves data based on American Petroleum Institute estimates. 1979 to 1982 data based on U.S. Department of Energy estimates. Figures may not add due to rounding.

[b] Includes field condensate.

[c] Proved crude oil remaining recoverable reserves as at December 31. Gulf of Mexico proved crude reserves included in Louisiana and Texas State Totals. New York proved crude reserves for 1979 to 1982 included in miscellaneous.

TABLE B.4

1982 U.S. CRUDE OIL PRODUCTION AND REMAINING RECOVERABLE RESERVES FOR SELECTED STATES[a]

($10^6 m^3$)

	Production[b]	% of PADD Total	% of U.S. Total	Remaining Recoverable Reserves	% of PADD Total	% of U.S. Total
PADD I						
Florida	4.1	75.9	0.8	15.4	53.3	0.3
New York[c]	0.1	1.9	—	c	—	—
Pennsylvania	0.7	13.0	0.1	5.9	20.4	0.1
Virginia[d]	—	—	—	—	—	—
West Virginia	0.5	9.3	0.1	7.6	26.3	0.2
Total	5.4	100.0	1.1	28.9	100.0	0.7
PADD II						
Illinois	4.4	7.4	0.9	23.8	7.1	0.5
Indiana	0.9	1.5	0.2	4.5	1.3	0.1
Kansas	11.2	18.9	2.2	60.1	17.8	1.4
Kentucky	1.2	2.0	0.2	5.7	1.7	0.1
Michigan	5.0	8.5	1.0	29.3	8.7	0.7
Missouri	—	—	—	—	—	—
Nebraska	1.1	1.9	0.2	5.1	1.5	0.1
N. Dakota	7.5	12.7	1.5	37.7	11.1	0.9
Ohio	2.3	3.9	0.5	17.6	5.2	0.4
Oklahoma	25.2	42.6	5.0	154.4	45.7	3.5
S. Dakota	0.2	0.3	—	—	—	—
Tennessee	0.2	0.3	—	—	—	—
Total	59.2	100.0	11.8	338.2	100.0	7.6
PADD III[e]						
Alabama	3.2	1.3	0.6	8.6	0.5	0.2
Arkansas	3.0	1.2	0.6	17.0	0.9	0.4
Louisiana	72.8	30.0	14.5	433.7	24.2	9.8

Continued on Next Page

TABLE B.4 (Continued)

	Production[b]	% of PADD Total	% of U.S. Total	Remaining Recoverable Reserves	% of PADD Total	% of U.S. Total
PADD III (Continued)						
Mississipi	5.3	2.2	1.1	35.5	2.1	0.8
New Mexico	11.3	4.7	2.3	89.5	5.0	2.0
Texas	147.1	60.6	29.3	1 210.8	67.5	27.3
Total	242.7	100.0	48.3	1 795.1	100.0	40.5
PADD IV						
Colorado	4.9	15.3	1.0	26.9	12.0	0.6
Montana	4.9	15.2	1.0	34.3	15.3	0.8
Utah	3.6	11.2	0.7	27.5	12.2	0.6
Wyoming	18.8	58.5	3.7	136.1	60.5	3.1
Total	32.1	100.0	6.4	224.8	100.0	5.1
PADD V						
Alaska	98.4	60.6	19.6	1 177.5	57.8	26.6
California	63.8	39.3	12.7	859.3	42.2	19.4
Nevada	0.2	0.1	—	—	—	—
Total	162.4	100.0	32.3	2 036.8	100.0	46.0
Miscellaneous	—	—	—	5.2	—	0.1
TOTAL U.S.[f]	501.9	NA	100.0	4 429.1	NA	100.0

SOURCE: De Golyer and MacNaughton, Twentieth Century Petroleum Statistics 1983 (Dallas, Texas: De Golyer and MacNaughton, 1983), pp. 18-26.

[a] PADD totals include all production/remaining recoverable reserves for that PADD, not just the states listed.

[b] Includes field condensate.

[c] New York 1982 proved crude oil remaining recoverable reserves included in miscellaneous.

[d] Virginia 1982 crude oil production was 28 900 cubic metres.

[e] Gulf of Mexico 1982 proved crude oil remaining recoverable reserves included in Louisiana and Texas state totals.

[f] Figures may not add due to rounding.

TABLE B.5

DISTRIBUTION OF CALIFORNIA 1982 CRUDE OIL PRODUCTION BY API GRAVITY

API Gravity	Production[a] ($10^3 m^3$)	Percentage[b]
0 - 19.9	39 584	62
20 - 24.9	7 023	11
25 - 31.9	8 300	13
32 - 39.9	8 300	13
40 - Over	638	1
TOTAL	63 845	100

SOURCE: Personal correspondence, Division of Oil and Gas, State of California.

[a] Production determined by applying the given percentage distribution to total 1982 California crude oil production.

[b] Percentages based on simple averages of crude quality distributions for January 1982 and January 1983.

TABLE B.6

CRUDE OIL PRODUCTION FOR SELECTED STATES
FOR P.A.D. DISTRICT II
1973-1982
($10^3 m^3$)

	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982
Illinois	4 876	4 381	4 144	4 177	4 071	3 714	3 465	3 646	3 830	4 406
Indiana	845	782	736	736	845	745	750	736	751	884
Kansas	10 529	9 808	9 397	9 335	9 141	8 996	9 061	9 563	10 463	11 213
Kentucky	1 381	1 246	1 201	1 190	1 046	910	877	943	1 041	1 168
Michigan	2 323	2 865	3 882	4 837	5 241	5 512	5 543	5 207	5 193	5 002
Missouri	10	9	9	10	10	9	14	11	36	32
Nebraska	1 151	1 051	973	983	949	932	965	994	1 061	1 093
N. Dakota	3 217	3 132	3 252	3 454	3 700	3 945	4 915	6 362	7 222	7 515
Ohio	1 398	1 445	1 523	1 589	1 647	1 773	1 900	1 990	2 154	2 317
Oklahoma	30 399	28 266	25 934	25 665	24 863	23 921	22 837	24 160	24 493	25 219
S. Dakota	44	79	75	71	100	138	135	125	155	184
Tennessee	32	122	108	95	130	94	98	118	146	180
TOTAL[a]	56 205	53 184	51 236	52 140	51 744	50 690	50 559	53 857	56 544	59 212

SOURCE: De Golyer and MacNaughton, *Twentieth Century Petroleum Statistics 1983* (Dallas, Texas: De Golyer and MacNaughton, 1983), p. 23.

[a] Figures may not add due to rounding.

TABLE B.7

PROVED CRUDE OIL REMAINING RECOVERABLE RESERVES FOR SELECTED STATES FOR P.A.D. DISTRICT II 1973–1982 ($10^6 m^3$)

	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982
Illinois	24	25	26	25	24	22	22	18	21	24
Indiana	4	4	4	4	4	4	6	4	4	4
Kansas	64	63	58	57	57	56	60	49	59	60
Kentucky	6	6	6	6	6	5	4	6	5	6
Michigan	12	13	15	22	21	30	25	33	38	29
Nebraska	4	4	5	5	5	5	4	7	7	5
North Dakota	29	27	25	24	24	26	34	34	35	38
Ohio	20	20	19	20	21	21	13	18	18	18
Oklahoma	202	196	197	189	178	171	161	148	151	154
TOTAL[a]	365	358	354	351	340	339	329	317	337	338

SOURCE: De Golyer and MacNaughton, Twentieth Century Petroleum Statistics, 1979 and 1983 editions (Dallas, Texas: De Golyer and MacNaughton, 1979 and 1983), p. 25 and 19, respectively.

[a] Figures may not add due to rounding.

TABLE B.8

CRUDE OIL PRODUCTION AND REMAINING RECOVERABLE RESERVES FOR SELECTED STATES FOR P.A.D. DISTRICT III 1973-1982

	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982
Production ($10^3 m^3$)										
Texas	205 836	200 622	194 271	189 119	180 908	170 760	161 864	155 050	150 264	147 110
Other	161 897	145 735	130 707	123 613	116 316	111 019	102 498	98 425	94 457	95 603
Total[a]	367 733	346 397	324 978	312 732	297 224	281 779	264 362	253 475	244 721	242 714
Remaining Recoverable Reserves ($10^6 m^3$)										
Texas	1 869	1 749	1 603	1 467	1 346	1 223	1 317	1 305	1 287	1 211
Other	901	841	764	694	626	587	594	532	622	584
Total[a]	2 771	2 590	2 366	2 161	1 972	1 810	1 911	1 887	1 909	1 795

SOURCE: De Golyer and MacNaughton, Twentieth Century Petroleum Statistics, 1979 and 1983 editions (Dallas, Texas: De Golyer and MacNaughton, 1979 and 1983), p. 25, and pp. 19 and 24, respectively.

[a] Figures may not add due to rounding.

TABLE B.9

CRUDE OIL PRODUCTION AND REMAINING RECOVERABLE RESERVES FOR SELECTED STATES FOR P.A.D. DISTRICT IV 1973-1982

	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982
Production ($10^3 m^3$)										
Colorado	5 817	5 963	6 056	6 199	6 274	5 755	5 139	4 700	4 818	4 856
Wyoming	22 563	22 258	21 613	21 328	21 697	21 842	20 969	20 558	20 758	18 808
Other	10 696	11 752	11 947	10 671	10 460	99 272	9 171	3 790	9 010	8 484
Total[a]	39 076	39 973	39 616	38 198	38 431	37 524	35 279	34 049	34 586	32 148
Remaining Recoverable Reserves ($10^6 m^3$)										
Colorado	48	46	44	40	38	31	25	29	23	27
Wyoming	146	144	139	132	130	128	134	148	134	136
Other	77	73	59	53	53	47	56	60	60	62
Total[a]	271	262	243	225	221	206	215	237	217	225

SOURCE: De Golyer and MacNaughton, Twentieth Century Petroleum Statistics, 1979 and 1983 editions (Dallas, Texas: De Golyer and MacNaughton, 1979 and 1983), p. 25, and pp. 19 and 26, respectively.

[a] Figures may not add due to rounding.

TABLE B.10

CRUDE OIL PRODUCTION AND REMAINING RECOVERABLE RESERVES FOR SELECTED STATES FOR P.A.D. DISTRICT V 1973-1982

	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982
Production ($10^3 m^3$)										
Alaska	11 498	11 225	11 103	10 080	26 106	71 325	81 296	94 070	93 379	98 399
California	53 432	51 353	51 225	51 833	55 583	55 197	56 006	56 702	61 203	63 845
Other	143	138	119	105	968	250	271	245	168	151
Total[a]	65 073	62 716	62 447	62 018	82 657	126 772	137 573	151 017	154 750	162 394
Remaining Recoverable Reserves ($10^6 m^3$)										
Alaska	1 609	1 605	1 596	1 556	1 529	1 470	1 411	1 391	1 317	1 177
California	555	566	580	571	577	552	837	870	865	859
Other	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR
Total[a]	2 162	2 170	2 176	2 127	2 106	2 022	2 248	2 261	2 182	2 037

SOURCE: De Golyer and MacNaughton, Twentieth Century Petroleum Statistics, 1979 and 1983 editions (Dallas, Texas: De Golyer and MacNaughton, 1979 and 1983), p. 25, and pp. 19 and 26, respectively.

[a] Figures may not add due to rounding.

TABLE B.11

DISPOSITION OF CANADIAN CRUDE OIL PRODUCTION
1978-1983
(10^6m^3)

Destination	Alberta Production						Saskatchewan Production						Total Canadian Production						Disposition as a % of Total 1983 Production
	1978	1979	1980	1981	1982	1983	1978	1979	1980	1981	1982	1983	1978	1979	1980	1981	1982	1983	
Canada:																			
B.C.	6.5	7.5	7.5	7.5	6.8	5.8	-	-	-	-	-	-	8.7	9.6	9.6	9.7	9.0	7.9	9.4
Alberta	13.9	15.9	15.7	15.4	13.8	15.2	-	-	-	-	-	-	13.9	15.9	15.7	15.4	13.9	15.2	18.1
Sask.	1.2	1.8	2.2	2.3	2.0	1.6	0.2	0.5	0.3	0.1	0.1	0.2	1.4	2.3	2.4	2.4	2.1	1.8	2.1
Manitoba	1.5	1.3	1.4	1.1	1.5	0.8	0.3	0.4	0.4	0.3	0.2	0.1	1.8	1.7	1.9	1.6	1.7	0.9	1.1
Ontario	22.2	28.1	28.0	27.4	23.1	25.0	4.7	3.2	2.8	2.2	1.9	1.8	27.5	31.8	31.3	29.8	25.2	27.0	32.1
Quebec	14.0	14.4	15.0	11.0	11.7	9.6	0.6	1.2	1.6	1.2	1.1	1.7	14.6	15.7	16.6	12.3	13.2	11.6	13.8
Atlantic	-	-	-	-	1.4	2.6	-	-	-	-	-	-	-	-	-	-	1.4	2.6	3.1
NWT	-	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1	0.2	0.2	0.2	0.2	0.2
Total	59.3	69.1	69.7	64.6	60.3	60.6	5.8	5.2	5.1	3.7	3.3	3.7	68.0	77.2	77.6	71.2	66.6	67.4	80.0
U.S.:																			
PADD I	0.6	0.6	0.3	0.1	-	1.1	-	-	-	-	-	0.1	0.6	0.6	0.4	0.1	-	1.2	1.4
PADD II	6.6	6.7	3.5	2.8	4.4	6.3	3.9	4.1	4.2	3.6	4.5	5.8	10.6	10.8	7.8	6.5	8.9	12.2	14.5
PADD III	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PADD IV	3.4	3.6	2.5	1.7	2.4	2.5	-	-	-	-	-	-	3.4	3.6	2.5	1.7	2.4	2.5	3.0
PADD V	0.8	1.5	1.2	1.1	1.1	0.9	-	-	-	-	-	-	0.9	1.7	1.2	1.2	1.1	0.9	1.1
Total	11.4	12.4	7.6	5.8	7.9	10.8	3.9	4.2	4.3	3.6	4.5	5.9	15.4	16.8	11.9	9.5	12.4	16.8	20.0
TOTAL Canada & U.S.	70.7	81.5	77.3	70.4	68.2	71.4	9.7	9.4	9.4	7.3	7.8	9.6	83.4	94.0	89.5	80.7	79.0	84.2	100.0

SOURCE: Canada, Statistics Canada, Crude Petroleum and Natural Gas Production, Catalogue No. 26-006, Monthly (Ottawa: Minister of Supply and Services Canada, December 1978 to December 1983), Table 3 for 1978 to 1982 editions, Table 2 for 1983 edition.

TABLE B.12

CANADIAN AND U.S. LIGHT AND HEAVY REFINED PRODUCTS SUPPLY AND DEMAND
1973-1983

Year	Canadian Supply[a]			Canadian Domestic Demand[a]			United States Supply[b]			United States Domestic Demand[b]		
	Light (10^6m^3)	Heavy (10^6m^3)	Light/ Total (%)	Light (10^6m^3)	Heavy (10^6m^3)	Light/ Total (%)	Light (10^6m^3)	Heavy (10^6m^3)	Light/ Total (%)	Light (10^6m^3)	Heavy (10^6m^3)	Light/ Total (%)
1973	NR	NR	NA	NR	NR	NA	NR	NR	81.2	640.8	305.7	63.0
1974	71.8	29.0	69.9	68.0	25.5	72.0	NR	NR	80.5	618.3	288.3	64.0
1975	71.5	26.6	72.4	72.2	23.1	78.1	NR	NR	80.5	619.9	270.9	65.4
1976	73.1	26.6	73.6	70.7	24.8	73.3	NR	NR	79.6	636.2	295.9	62.8
1977	75.5	30.2	72.0	69.7	26.0	72.2	NR	NR	77.8	681.4	309.3	63.7
1978	76.0	31.0	72.1	71.8	26.4	72.7	NR	NR	77.5	710.6	306.2	65.0
1979	81.4	33.1	71.0	74.7	27.4	72.9	NR	NR	77.1	690.2	300.9	64.2
1980	81.1	31.1	72.3	74.3	25.9	73.9	NR	NR	77.3	643.2	277.3	65.0
1981	75.1	28.5	72.3	69.8	23.5	74.5	NR	NR	78.7	612.3	252.8	65.7
1982	67.0	22.6	74.1	64.3	19.6	76.2	NR	NR	81.7	600.8	230.4	67.7
1983	64.5	21.0	74.7	61.1	17.4	77.6	NR	NR	82.6	NR	NR	NA

SOURCES: (1) American Petroleum Institute, Basic Petroleum Data Book, Volume IV, Number 3, September 1984 (Washington, D.C.: American Petroleum Institute, 1984), Section VII, Tables 2, 4-6, and 13-17, Section VIII, Table 4; and (2) Canada, Statistics Canada, Refined Petroleum Products, Catalogue No. 45-004, Monthly, December Edition 1974 to 1983, and April 1984 (Ottawa: Minister of Supply and Services Canada, 1974-1984), Table on Supply and Disposition of Petroleum Products, Canada.

[a] Canadian supply and demand figures are production and domestic sales data, respectively. Light products include naphtha specialties, aviation gasoline, motor gasoline, aviation turbo fuel (kerosene-type and naphtha-type), kerosene stove oil (tractor), diesel fuel oil, light fuel oil (Nos. 2 and 3), and still gas. Heavy products include propane and propane mixes, butane and butane mixes, petro-chemical feedstocks, heavy fuel oil (Nos. 4, 5 and 6), asphalt, coke, and lubricating oil and grease.

[b] Supply and demand figures are percentage yields of refined products and domestic demand, respectively. Light products demand includes motor gasoline, jet fuel (naphtha and kerosene), kerosene, and distillate fuel oil. Heavy products demand includes NGL's and liquefied refinery gases, residual fuel oil, and lubricants. Light products supply also includes special naphthas and still gas. Heavy products supply does not specify NGL's and liquefied refinery gases, but includes ethane and ethylene, liquefied gases, petrochemical feedstocks, lubricants, wax, coke, asphalt, and road oil in addition to the demand elements.

TABLE B.13

TOTAL RECEIPTS OF DOMESTIC AND IMPORTED CRUDE BY CANADIAN REFINERIES
1980-1983

	Light and Medium Crude Oil (10^3m^3)				Heavy Crude Oil[a] (10^3m^3)				Total (10^3m^3)				Heavy Crude/ Total (%)			
	1980	1981	1982	1983	1980	1981	1982	1983	1980	1981	1982	1983	1980	1981	1982	1983
Domestic																
B.C.	9 549	9 629	9 043	7 938	6	7	14	2	9 555	9 636	9 057	7 940	—	—	—	—
Prairies	17 897	17 591	16 517	16 747	2 217	1 805	1 436	1 665	20 114	19 396	17 953	18 412	11.0	9.3	8.0	9.0
Ontario	31 739	28 966	24 894	25 773	2 538	2 699	2 492	1 974	34 297	31 665	27 386	27 747	7.5	8.5	9.1	7.1
Quebec	18 020	11 247	12 933	11 764	2 349	2 477	1 435	478	20 369	13 724	14 368	12 242	11.5	18.0	10.0	3.9
Atlantic	99	-	1 335	2 700	-	-	-	-	99	-	1 335	2 700	-	-	-	-
Total	77 304	67 433	64 722	64 922	7 130	6 988	5 377	4 119	84 434	74 421	70 099	69 041	8.4	9.4	7.7	6.0
Imported																
Ontario	NR	NR	144	53	NR	NR	-	-	59	160	144	53	NA	NA	-	-
Quebec	NR	NR	5 772	4 327	NR	NR	3 490	2 869	9 175	13 782	9 262	7 196	NA	NA	37.7	39.9
Atlantic	NR	NR	5 571	3 295	NR	NR	884	1 410	16 077	12 088	6 455	4 705	NA	NA	13.7	30.0
Total	20 755	20 564	11 343	7 622	4 556	5 466	4 374	4 279	25 311	26 030	15 861	11 954	18.0	21.0	27.8	36.0
Total																
B.C.	9 549	9 629	9 043	7 938	6	7	14	2	9 555	9 636	9 057	7 940	-	-	-	-
Prairies	17 897	17 591	16 517	16 747	2 217	1 805	1 436	1 665	20 114	19 396	17 953	18 412	11.0	9.3	8.0	9.0
Ontario	NR	NR	25 038	25 826	NR	NR	2 492	1 974	34 356	31 825	27 530	27 800	NA	NA	9.1	7.1
Quebec	NR	NR	18 705	16 091	NR	NR	4 925	3 347	29 544	27 506	23 630	19 438	NA	NA	20.8	17.2
Atlantic	NR	NR	6 906	5 995	NR	NR	884	1 410	16 176	12 088	7 790	7 405	NA	NA	11.3	19.0
Total	98 059	87 997	76 065	72 544	11 686	12 454	9 751	8 398	109 745	100 451	85 960	80 995	10.6	12.4	11.3	10.4

SOURCE: Personal correspondence, Energy, Mines and Resources Canada, Ottawa.

[a] Heavy crude oil defined as less than 30° API.

TABLE B.14

CONFIGURATION OF CANADIAN REFINERIES NOMINATING FOR DOMESTIC HEAVY CRUDE OIL
1970-1984

	1970[a]	1975	1980	1981	1982	1983	1984
Crude Capacity							
m^3/cd	84 329	120 704	125 423	125 42	124 3603	121 463	125 590
m^3/sd	39 154	43 929	92 177	92 17	91 7957	89 445	94 055
Charge Capacity (m^3/sd)							
Vacuum Distillation	33 974	41 702	45 521	45 521	46 321	46 121	47 835
Thermal Operations	6 121	5 580	5 532	5 532	4 172	6 397	6 995
Catalytic Fresh Feed	22 211	23 290	28 380	28 380	29 010	29 570	29 500
Cracking Recycle	5 962	1 113	1 090	1 090	5 430	475	-
Catalytic Reforming	11 352	26 027	27 224	27 224	31 731	26 531	25 260
Hydro Refining	-	9 699	10 020	10 020	-	9 380	1 750
Production Capacity (m^3/sd)							
Hydro Treating	34 390	39 238	46 483	46 483	46 413	46 218	48 775
Hydro Cracking	572	7 091	7 629	7 629	7 679	7 604	7 455
Alkylation	1 313	3 349	3 604	3 604	3 669	3 664	4 310
Polymerization	611	401	1 075	875	955	950	950
Lubes	1 538	2 154	3 214	3 214	3004	2 994	2 850
Asphalt	6 798	6 308	9 471	9 471	7 591	7 801	6 382
Coke (tonnes)	200	100	-	-	-	-	-
Sulphur (tonnes)	177	225	217	210	199	200	220
Total Number of Cdn. Refineries	40	40	39	39	40	31	29
Cdn. Refinery Utilization (%)	91.4	81.5	87.8	81.4	72.0	76.7	NR

LEGEND: m^3/cd = cubic metres per calendar day m^3/sd = cubic metres per stream day

SOURCES: (1) Canadian Petroleum Association, CPA Statistical Handbook, updated to 1984 (Calgary: Canadian Petroleum Association, 1984), Section VIII, Table 6; and (2) "Refinery and Petrochemical Report," Oilweek, June 8, 1970; June 23, 1975; June 9, 1980; May 18, 1981; June 14, 1982; May 30, 1983; April 16, 1984.

[a] 1970 Hydro Treating and Hydro Cracking capacity given as Charge Capacity.

TABLE B.15

CHEVRON CANADA REFINERY CONFIGURATION
BURNABY, BRITISH COLUMBIA
1970-1984

	1970*	1975	1980	1981	1982	1983	1984
Crude Capacity							
m^3/cd	2 862	3 498	5 560	5 560	5 560	5 560	5 560
m^3/sd	3 005	-	-		-	-	-
Charge Capacity (m^3/sd)							
Vacuum Distillation	1 336	1 336	1 340	1 340	1 340	1 340	1 340
Thermal Operations	-	-	-	-	-	-	-
Catalytic Fresh Feed	795	1 272	1 270	1 270	1 270	1 670	1 670
Cracking Recycle	636	159	160	160	160	-	-
Catalytic Reforming	477	541	1 590	1 590	1 590	1 590	1 590
Hydro Refining	-	-	-	-	-	-	-
Production Capacity (m^3/sd)							
Hydro Treating	-	541	1 590	1 590	1 590	1 590	1 590
Hydro Cracking	-	-	-	-	-	-	-
Alkylation		-	-	-	-	-	-
Polymerization	64	95	100	100	100	100	100
Lubes	-	-	-	-	-	-	-
Asphalt	350	350	350	350	350	350	350
Coke (tonnes)	-	-	-	-	-	-	-
Sulphur (tonnes)	-	-	7	-	-	-	-

LEGEND: m^3/cd = cubic metres per calendar day m^3/sd = cubic metres per stream day

SOURCE: "Refinery and Petrochemical Report," Oilweek, June 8, 1970; June 23, 1975; June 9, 1980; May 18, 1981; June 14, 1982; May 30, 1983; April 16, 1984.

*1970 Hydro Treating and Hydro Cracking capacity given as Charge Capacity.

TABLE B.16

ESSO PETROLEUM REFINERY CONFIGURATION
EDMONTON, ALBERTA
1970-1984

	1970[a]	1975	1980	1981	1982	1983	1984
Crude Capacity							
m^3/cd	6 344	22 258	24 010	24 010	24 100	24 100	28 200
m^3/sd	-	-	24 690	24 690	24 900	24 900	29 000
Charge Capacity (m^3/sd)							
Vacuum Distillation	2 480	5 088	8 010	8 010	8 000	8 000	10 400
Thermal Operations	-	-	-	-	-	-	-
Catalytic Fresh Feed	1 622	6 518	7 160	7 160	7 500	7 500	7 900
Cracking Recycle	1 463	-	-	-	NR	-	-
Catalytic Reforming	413	3 498	3 500	3 500	3 400	3 400	3 500
Hydro Refining	-	-	-	-	-	-	-
Production Capacity (m^3/sd)							
Hydro Treating	318	7 313	7 470	7 470	7 300	7 300	7 300
Hydro Cracking	-	-	-	-	-	-	-
Alkylation	334	1 351	1 590	1 590	1 600	1 600	2 100
Polymerization	-	-	-	-	-	-	-
Lubes	318	461	460	460	500	500	500
Asphalt	541	-	2 000	2 000	NR	NR	NR
Coke (tonnes)	-	-	-	-	-	-	-
Sulphur (tonnes)	-	40	36	36	20	20	40

LEGEND: m^3/cd = cubic metres per calendar day m^3/sd = cubic metres per stream day

SOURCE: "Refinery and Petrochemical Report," Oilweek, June 8, 1970; June 23, 1975; June 9, 1980; May 18, 1981; June 14, 1982; May 30, 1983; April 16, 1984.

[a] 1970 Hydro Treating and Hydro Cracking capacity given as Charge Capacity.

TABLE B.17

GULF CANADA REFINERY CONFIGURATION
CALGARY, ALBERTA
1970-1984

	1970[a]	1975	1980	1981	1982	1983	1984[b]
Crude Capacity							
m^3/cd	1 431	1 383	1 380	1 380	2 051	2 050	-
m^3/sd	1 590	1 479	1 480	1 480	2 194	2 190	-
Charge Capacity (m^3/sd)							
Vacuum Distillation	397	397	400	400	970	970	-
Thermal Operations	397	-	-	-	-	-	-
Catalytic Fresh Feed	-	-	-	-	-	-	-
Cracking Recycle	-	-	-	-	-	-	-
Catalytic Reforming	477	-	-	-	-	-	-
Hydro Refining	-	-	-	-	-	-	-
Production Capacity (m^3/sd)							
Hydro Treating	556	-	-	-	-	-	-
Hydro Cracking	-	-	-	-	-	-	-
Alkylation	-	-	-	-	-	-	-
Polymerization	-	-	-	-	-	-	-
Lubes	-	-	-	-	-	-	-
Asphalt	270	350	830	830	800	800	-
Coke (tonnes)	-	-	-	-	-	-	-
Sulphur (tonnes)	-	-	-	-	-	-	-

LEGEND: m^3/cd = cubic metres per calendar day m^3/sd = cubic metres per stream day

SOURCE: "Refinery and Petrochemical Report," Oilweek, June 8, 1970; June 23, 1975; June 9, 1980; May 18, 1981; June 14, 1982; May 30, 1983; April 16, 1984.

[a] 1970 Hydro Treating and Hydro Cracking capacity given as Charge Capacity.
[b] Shut down in late 1983.

TABLE B.18

HUSKY OIL REFINERY CONFIGURATION
LLOYDMINSTER, ALBERTA
1970-1984

	1970[a]	1975	1980	1981	1982	1983	1984
Crude Capacity							
m^3/cd	1 033	1 781	1 820	1 820	1 820	3 740	3 740
m^3/sd	1 113	1 908	1 900	1 900	1 900	3 975	3 975
Charge Capacity (m^3/sd)							
Vacuum Distillation	556	1 113	1 110	1 110	1 110	2 385	2 385
Thermal Operations	-	-	-	-	-	-	-
Catalytic Fresh Feed	-	-	-	-	-	-	-
Cracking Recycle	-	-	-	-	-	-	-
Catalytic Reforming	159	159	-	-	-	-	-
Hydro Refining	-	-	-	-	-	-	-
Production Capacity (m^3/sd)							
Hydro Treating	159	159	-	-	-	-	-
Hydro Cracking	-	-	-	-	-	-	-
Alkylation	-	-	-	-	-	-	-
Polymerization	-	-	-	-	-	-	-
Lubes	-	-	-	-	-	-	-
Asphalt	477	874	870	870	870	1 990	1 990
Coke (tonnes)	-	-	-	-	-	-	-
Sulphur (tonnes)	-	-	-	-	-	-	-

LEGEND: m^3/cd = cubic metres per calendar day m^3/sd = cubic metres per stream day

SOURCE: "Refinery and Petrochemical Report," Oilweek, June 8, 1970; June 23, 1975; June 9, 1980; May 18, 1981; June 14, 1982; May 30, 1983; April 16, 1984.

[a] 1970 Hydro Treating and Hydro Cracking capacity given as Charge Capacity.

TABLE B.19

GULF CANADA REFINERY CONFIGURATION
MOOSE JAW, SASKATCHEWAN
1970–1984

	1970^a	1975	1980	1981	1982	1983	1984
Crude Capacity							
m^3/cd	2 146	1 479	2 110	2 110	2 115	2 110	2 110
m^3/sd	2 385	1 590	2 230	2 230	2 226	2 230	2 230
Charge Capacity (m^3/sd)							
Vacuum Distillation	874	874	1 220	1 220	1 220	1 220	1 220
Thermal Operations	-	-	-	-	-	-	-
Catalytic Fresh Feed	715	-	-	-	-	-	-
Cracking Recycle	-	-	-	-	-	-	-
Catalytic Reforming	858	-	-	-	-	-	-
Hydro Refining	-	-	-	-	-	-	-
Production Capacity (m^3/sd)							
Hydro Treating	1 002	-	-	-	-	-	-
Hydro Cracking	-	-	-	-	-	-	-
Alkylation	-	-	-	-	-	-	-
Polymerization	62	-	-	-	-	-	-
Lubes	-	-	-	-	-	-	-
Asphalt	135	473	920	920	910	910	910
Coke (tonnes)	100	-	-	-	-	-	-
Sulphur (tonnes)	-	-	-	-	-	-	-

LEGEND: m^3/cd = cubic metres per calendar day m^3/sd = cubic metres per stream day

SOURCE: "Refinery and Petrochemical Report," Oilweek, June 8, 1970; June 23, 1975; June 9, 1980; May 18, 1981; June 14, 1982; May 30, 1983; April 16, 1984.

^{a}1970 Hydro Treating and Hydro Cracking capacity given as Charge Capacity.

TABLE B.20

ESSO PETROLEUM REFINERY CONFIGURATION
SARNIA, ONTARIO
1970-1984

	1970[a]	1975	1980	1981	1982	1983	1984
Crude Capacity							
m^3/cd	19 492	20 716	20 030	20 030	20 000	20 000	20 000
m^3/sd	-	-	20 067	20 067	20 700	20 700	20 700
Charge Capacity (m^3/sd)							
Vacuum Distillation	4 658	4 849	4 770	4 770	4 800	4 800	4 800
Thermal Operations	2 862	3 434	3 560	3 560	2 200	2 200	2 200
Catalytic Fresh Feed	3 736	3 625	4 130	4 130	4 100	4 100	3 800
Cracking Recycle	1 876	-	-	-	NR	-	-
Catalytic Reforming	5 437	5 135	4 930	4 930	4 800	4 800	4 900
Hydro Refining	-	-	-	-	-	-	-
Production Capacity (m^3/sd)							
Hydro Treating	13 418	13 339	15 070	15 070	14 500	14 500	10 800
Hydro Cracking	-	1 447	1 830	1 830	1 800	1 800	1 800
Alkylation	-	1 129	950	950	1 000	1 000	1 000
Polymerization	-	-	510	310	500	500	500
Lubes	556	938	1 030	1 030	1 000	1 000	1 000
Asphalt	366	-	-	-	-	-	-
Coke (tonnes)	-	-	-	-	-	-	-
Sulphur (tonnes)	102	114	103	103	100	100	100

LEGEND: m^3/cd = cubic metres per calendar day m^3/sd = cubic metres per stream day

SOURCE: "Refinery and Petrochemical Report," Oilweek, June 8, 1970; June 23, 1975; June 9, 1980; May 18, 1981; June 14, 1982; May 30, 1983; April 16, 1984.

[a] 1970 Hydro Treating and Hydro Cracking capacity given as Charge Capacity.

TABLE B.21

SHELL CANADA REFINERY CONFIGURATION
SARNIA, ONTARIO
1970–1984

	1970[a]	1975	1980	1981	1982	1983	1984
Crude Capacity							
m^3/cd	6 678	12 719	11 765	11 765	11 765	11 765	11 290
m^3/sd	-	-	-	-	-	-	-
Charge Capacity (m^3/sd)							
Vacuum Distillation	3 100	3 498	4 134	4 134	4 134	4 134	3 980
Thermal Operations	636	556	541	541	541	541	540
Catalytic Fresh Feed	2 226	2 385	2 544	2 544	2 544	2 544	2 700
Cracking Recycle	-	-	-	-	-	-	-
Catalytic Reforming	477	2 623	3 704	3 704	3 704	3 704	3 660
Hydro Refining	-	-	-	-	-	-	-
Production Capacity (m^3/sd)							
Hydro Treating	1 002	3 418	3 767	3 767	3 767	3 767	3 760
Hydro Cracking	572	1 272	1 1921	1 192	1 192	1 192	1 190
Alkylation	103	1 129	950	950	1 000	1 000	-
Polymerization	-	-	-	-	-	-	-
Lubes	-	-	-	-	-	-	-
Asphalt	-	-	-	-	-	-	-
Coke (tonnes)	-	-	-	-	-	-	-
Sulphur (tonnes)	35	114	103	103	100	100	100

LEGEND: m^3/cd = cubic metres per calendar day m^3/sd = cubic metres per stream day

SOURCE: "Refinery and Petrochemical Report," Oilweek, June 8, 1970; June 23, 1975; June 9, 1980; May 18, 1981; June 14, 1982; May 30, 1983; April 16, 1984.

[a] 1970 Hydro Treating and Hydro Cracking capacity given as Charge Capacity.

TABLE B.22

GULF CANADA REFINERY CONFIGURATION
CLARKSON, ONTARIO
1970-1984

	1970[a]	1975	1980	1981	1982	1983	1984
Crude Capacity							
m^3/cd	8 809	9 921	12 580	12 580	12 178	9 540	9 540
m^3/sd	9 773	10 652	13 510	13 510	13 069	10 330	10 330
Charge Capacity (m^3/sd)							
Vacuum Distillation	4 452	4 452	4 450	4 450	4 450	3 500	3 500
Thermal Operations	-	-	-	-	-	-	-
Catalytic Fresh Feed	2 862	2 862	2 60	2 860	3 100	3 100	3 100
Cracking Recycle	-	-	-	-	2 860	-	-
Catalytic Reforming	1 590	3 180	3 180	3 130	5 090	2 860	1 430
Hydro Refining	-	4 770	5 090	5 090	-	5 090	1 750
Production Capacity (m^3/sd)							
Hydro Treating	3 180	-	1 590	1 590	1 750	1 750	3 340
Hydro Cracking	-	-	-	-	-	-	-
Alkylation	477	477	570	570	570	570	570
Polymerization	200	-	200	200	110	110	110
Lubes	194	194	1 030	1 030	810	810	810
Asphalt	1 447	1 081	1 020	1 020	890	890	-
Coke (tonnes)	-	-	-	-	-	-	-
Sulphur (tonnes)	40	40	40	40	48	49	49

LEGEND: m^3/cd = cubic metres per calendar day m^3/sd = cubic metres per stream day

SOURCE: "Refinery and Petrochemical Report," Oilweek, June 8, 1970; June 23, 1975; June 9, 1980; May 18, 1981; June 14, 1982; May 30, 1983; April 16, 1984.

[a] 1970 Hydro Treating and Hydro Cracking capacity given as Charge Capacity.

TABLE B.23

PETROFINA, PETRO-CANADA REFINERY CONFIGURATION
MONTREAL, QUEBEC
1970–1984

	1970[a]	1975	1980	1981	1982	1983	1984
Crude Capacity							
m^3/cd	8 903	14 786	14 800	14 800	15 200	14 300	14 300
m^3/sd	9 364	15 104	15 100	15 100	15 550	15 100	15 100
Charge Capacity (m^3/sd)							
Vacuum Distillation	3 816	7 154	7 150	7 150	7 360	6 835	6 840
Thermal Operations	795	-	-	-	-	2 225	2 175
Catalytic Fresh Feed	3 021	3 130	3 180	3 180	3 270	3 180	3 000
Cracking Recycle	477	954	930	930	980	475	-
Catalytic Reforming	1 908	5 088	5 100	5 100	5 200	5 090	5 090
Hydro Refining	-	-	-	-	-	-	-
Production Capacity (m^3/sd)							
Hydro Treating	2 703	5 247	6 360	6 360	6 870	6 675	6 675
Hydro Cracking	-	2 544	2 540	2 540	2 620	2 545	2 545
Alkylation	238	238	240	240	245	240	240
Polymerization	87	95	95	95	75	80	80
Lubes	-	-	-	-	-	-	-
Asphalt	795	1 272	1 300	1 300	1 630	1 590	1 590
Coke (tonnes)	100	100	-	-	-	-	-
Sulphur (tonnes)	-	-	-	-	-	-	-

LEGEND: m^3/cd = cubic metres per calendar day m^3/sd = cubic metres per stream day

SOURCE: "Refinery and Petrochemical Report," Oilweek, June 8, 1970; June 23, 1975; June 9, 1980; May 18, 1981; June 14, 1982; May 30, 1983; April 16, 1984.

[a] 1970 Hydro Treating and Hydro Cracking capacity given as Charge Capacity.

TABLE B.24

SHELL CANADA REFINERY CONFIGURATION
MONTREAL, QUEBEC
1970-1984

	1970[a]	1975	1980	1981	1982	1983	1984
Crude Capacity							
m^3/cd	15 899	19 873	19 078	19 078	19 078	19 078	19 080
m^3/sd	-	-	-	-	-	-	-
Charge Capacity (m^3/sd)							
Vacuum Distillation	7 631	8 267	8 267	8 267	8 267	8 267	8 280
Thermal Operations	1 431	7 590	1 431	1 431	1 431	1 431	2 080
Catalytic Fresh Feed	3 736	3 736	3 736	3 736	3 736	3 736	3 590
Cracking Recycle	1 033	-	-	-	-	-	-
Catalytic Reforming	2 258	3 736	3 657	3 657	3 657	3 657	3 660
Hydro Refining	-	-	-	-	-	-	-
Production Capacity (m^3/sd)							
Hydro Treating	7 123	9 221	10 636	10 636	10 636	10 636	11 010
Hydro Cracking	-	1 828	2 067	2 067	2 067	2 067	1 920
Alkylation	254	254	254	254	254	254	400
Polymerization	-	-	-	-	-	-	-
Lubes	375	761	524	524	524	524	540
Asphalt	1 272	1 272	1 271	1 271	1 271	1 271	1 542
Coke (tonnes)	-	-	-	-	-	-	-
Sulphur (tonnes)	-	-	-	-	-	-	-

LEGEND: m^3/cd = cubic metres per calendar day m^3/sd = cubic metres per stream day

SOURCE: "Refinery and Petrochemical Report," Oilweek, June 8, 1970; June 23, 1975; June 9, 1980; May 18, 1981; June 14, 1982; May 30, 1983; April 16, 1984.

[a] 1970 Hydro Treating and Hydro Cracking capacity given as Charge Capacity.

TABLE 8.25

GULF CANADA REFINERY CONFIGURATION
MONTREAL, QUEBEC
1970-1984

	1970[a]	1975	1980	1981	1982	1983	1984
Crude Capacity							
m^3/cd	10 732	12 290	12 290	12 290	10 493	9 220	11 770
m^3/sd	11 924	13 196	13 200	13 200	11 256	10 020	12 720
Charge Capacity (m^3/sd)							
Vacuum Distillation	4 674	4 674	4 670	4 670	4 670	4 670	5 090
Thermal Operations	-	-	-	-	-	-	-
Catalytic Fresh Feed	3 498	3 498	3 500	3 500	3 490	3 740	3 740
Cracking Recycle	1 033	-	-	-	-	-	-
Catalytic Reforming	2 067	2 067	1 590	1 590	4 290	1 430	1 430
Hydro Refining	-	4 929	4 930	4 930	-	4 290	-
Production Capacity (m^3/sd)							
Hydro Treating	4 929	-	-	-	-	-	4 300
Hydro Cracking	-	-	-	-	-	-	-
Alkylation	-	-	-	-	-	-	-
Polymerization	100	100	170	170	170	160	160
Lubes	95	95	100	100	-	-	-
Asphalt	1 145	636	910	910	870	-	-
Coke (tonnes)	-	-	-	-	-	-	-
Sulphur (tonnes)	-	-	-	-	-	-	-

LEGEND: m^3/cd = cubic metres per calendar day m^3/sd = cubic metres per stream day

SOURCE: "Refinery and Petrochemical Report," Oilweek, June 8, 1970; June 23, 1975; June 9, 1980; May 18, 1981; June 14, 1982; May 30, 1983; April 16, 1984.

[a] 1970 Hydro Treating and Hydro Cracking capacity given as Charge Capacity.

TABLE B.26

CONFIGURATION OF SELECTED U.S. REFINERIES RECEIVING CANADIAN HEAVY CRUDE OIL
1970-1984

	1970	1975	1980	1981	1982	1983	1984
Crude Capacity							
m^3/cd	117 698	175 569	184 251	183 566	173 359	172 517	172 994
m^3/sd	91 895	172 469	194 426	195 189	195 666	193 964	194 476
Charge Capacity (m^3/sd)							
Vacuum Distillation	45 534	70 670	81 322	81 195	82 991	88 715	91 020
Thermal Operations	8 585	17 012	15 899	15 899	15 581	15 740	19 714
Cat Cracking							
Fresh Feed	61 003	54 692	72 450	72 927	73 722	73 722	72 214
Recycle	19 086	8 951	4 102	4 102	3 466	3 625	3 625
Cat Reforming	25 517	41 782	42 132	42 609	45 391	46 027	46 154
Cat Hydro Cracking	3 816	4134	4 134	4 134	4 134	4134	4 134
Cat Hydro Refining	11 956	21 193	25 168	13 880	13 880	18 967	19 555
Cat Hydro Treating	39 349	66 298	71 474	83 875	89 058	91 602	94 677
Production Capacity (m^3/sd)							
Alkylation Polymerization	11 876	12 989	13 442	13 601	14 237	14 237	14 810
Aromatics Isomerization	2 210	1 813	6 137	5 660	6 026	6 026	5 946
Lubes	1 404	1 256	986	1 018	1 018	1 018	1 018
Asphalt	7 926	13 554	18 180	18 101	17 862	17 974	17 133
Hydrogen ($10^6 m^3$/d)	-	-	0.4	1.8	1.8	1.8	1.8
Coke (tonnes/d)	3 302	4 518	5 108	5 108	5 153	5 153	6 299
Total Number of U.S. Refineries	NR	NR	319	324	301	258	247

LEGEND: m^3/cd = cubic metres per calendar day m^3/sd = cubic metres per stream day

SOURCE: Tables B.27 to B.35.

TABLE B.27

KOCH REFINERY CONFIGURATION
PINE BEND, MINNESOTA
1970-1984

	1970[a]	1975	1980	1981	1982	1983	1984
Crude Capacity							
m^3/cd	12 290	17 457	20 239	20 239	20 239	21 145	21 781
m^3/sd	12 719	17 807	20 971	20 971	20 971	21 781	22 576
Charge Capacity (m^3/sd)							
Vacuum Distillation	4 038	6 359	12 719	12 719	14 150	12 719	15 899
Thermal Operations	3 577	3 657	3 657	3 657	3 657	3 816	7 631
Cat Cracking							
Fresh Feed	5 199	6 042	8 426	8 426	8 426	8 426	8 744
Recycle	2 122	906	159	159	159	159	159
Cat Reforming	2 305	2 623	2 385	2 862	6 042	5 247	6 200
Cat Hydro Cracking	-	-	-	-	-	-	-
Cat Hydro Refining	-	-	7 313	7 313	7 313	6 836	6 916
Cat Hydro Treating	6 200	8 506	8 267	8 744	11 924	9 221	13 355
Production Capacity (m^3/sd)							
Alkylation Polymerization	1 113	1 351	1 526	1 526	1 526	1 526	2 115
Aromatics/Isomerization	-	-	-	-	-	-	-
Lubes	-	-	-	-	-	-	-
Asphalt	509	3 180	5 565	5 565	5 565	5 565	5 565
Hydrogen ($10^3 m^3$/d)	-	-	396	396	396	396	467
Coke (tonnes/d)	139	139	139	139	139	139	268

LEGEND: m^3/cd = cubic metres per calendar day m^3/sd = cubic metres per stream day

SOURCE: "Annual Refining Survey," Oil and Gas Journal, various issues, 1970-1984.

[a] Operated by Great Northern Oil Co. in 1970.

TABLE B.28

MOBIL OIL REFINERY CONFIGURATION
JOLIET, ILLINOIS
1970-1984

	1970	1975	1980	1981	1982	1983	1984
Crude Capacity							
m^3/cd	NR	27 823	28 618	28 618	28 618	28 618	28 618
m^3/sd	NR	45 470	31 797	31 797	31 797	31 797	31 797
Charge Capacity (m^3/sd)							
Vacuum Distillation	NR	13 037	13 991	13 991	13 991	13 991	13 991
Thermal Operations	NR	5 088	5 247	5 247	5 247	5 247	5 406
Cat Cracking							
Fresh Feed	NR	10 493	15 104	15 581	15 581	15 581	15 581
Recycle	NR	NR	-	NR	NR	-	-
Cat Reforming	NR	7 472	7 472	7 472	7 313	7 313	7 313
Cat Hydro Cracking	NR	-	-	-	-	-	-
Cat Hydro Refining	NR	11 924	11 288	-	-	-	-
Cat Hydro Treating	NR	11 765	11 765	23 689	23 371	24 802	24 802
Production Capacity (m^3/sd)							
Alkylation Polymerization	NR	3 316	3 816	3 816	3 816	3 816	3 816
Aromatics/Isomerization	NR	-	-	-	-	-	-
Lubes	NR	-	-	-	-	-	-
Asphalt	NR	-	-	-	-	-	-
Hydrogen ($10^3 m^3$/d)	NR	-	-	-	-	-	-
Coke (tonnes/d)	NR	195	223	223	223	223	230

LEGEND: m^3/cd = cubic metres per calendar day m^3/sd = cubic metres per stream day

SOURCE: "Annual Refining Survey," Oil and Gas Journal, various issues, 1970-1984.

TABLE B.29

AMOCO REFINERY CONFIGURATION
WHITING, INDIANA
1970-1984

	1970	1975	1980	1981	1982	1983	1984
Crude Capacity							
m^3/cd	46 901	57 235	60 415	60 415	60 415	59 779	59 779
m^3/sd	47 696	59 620	64 390	64 390	64 390	63 595	63 595
Charge Capacity (m^3/sd)							
Vacuum Distillation	20 350	26 551	28 618	28 618	28 618	35 772	35 772
Thermal Operations	3 975	3 816	3 657	3 657	3 180	3 180	3 180
Cat Cracking							
Fresh Feed	18 125	18 760	22 258	22 258	23 053	23 848	22 258
Recycle	6 042	4 563	1 590	1 590	954	1 113	1 113
Cat Reforming	6 836	14 468	14 468	14 468	14 309	15 740	14 945
Cat Hydro Cracking	-	-	-	-	-	-	-
Cat Hydro Refining	5 962	715	-	-	-	5 565	6 995
Cat Hydro Treating	8 665	23 053	25 463	25 463	26 576	30 392	28 188
Production Capacity (m^3/sd)							
Alkylation Polymerization	2 464	3 021	2 703	2 862	3 498	3 498	3 498
Aromatics/Isomerization	1 383	1 033	3 847	3 371	2 464	2 464	2 385
Lubes	1 431	1 256	986	1 018	1 018	1 018	1 018
Asphalt	3 180	3 180	6 359	6 359	6 359	6 359	6 359
Hydrogen (10^3m^3/d)	-	-	-	-	-	-	-
Coke (tonnes/d)	125	92	129	129	129	129	129

LEGEND: m^3/cd = cubic metres per calendar day m^3/sd = cubic metres per stream day

SOURCE: "Annual Refining Survey," Oil and Gas Journal, various issues, 1970-1984.

TABLE B.30

MARATHON REFINERY CONFIGURATION
DETROIT, MICHIGAN
1970-1984

	1970	1975	1980	1981	1982	1983	1984
Crude Capacity							
m^3/cd	7 631	10 334	10 891	10 891	10 891	10 891	10 891
m^3/sd	7 949	10 652	11 288	11 288	11 288	11 288	11 288
Charge Capacity (m^3/sd)							
Vacuum Distillation	3 975	3 975	4 134	4 134	4 134	4 134	4 134
Thermal Operations	1 033	-	-	-	-	-	-
Cat Cracking							
Fresh Feed	2 862	3 418	4 293	4 293	4 293	4 293	4 293
Recycle	2 289	620	207	207	207	207	207
Cat Reforming	2 544	2 544	2 703	2 703	2 703	2 703	2 703
Cat Hydro Cracking	-	-	-	-	-	-	-
Cat Hydro Refining	1 987	1 987	1 987	1 987	1 987	1 987	1 987
Cat Hydro Treating	2 862	2 623	2 782	2 782	2 782	2 782	2 782
Production Capacity (m^3/sd)							
Alkylation Polymerization	397	556	636	636	636	636	636
Aromatics/Isomerization	318	318	-	-	-	-	-
Lubes	-	-	-	-	-	-	-
Asphalt	1 375	1 375	1 375	1 375	1 375	1 375	1 375
Hydrogen ($10^3 m^3$/d)	-	-	-	-	-	-	-
Coke (tonnes/d)	18	-	-	-	-	-	-

LEGEND: m^3/cd = cubic metres per calendar day m^3/sd = cubic metres per stream day

SOURCE: "Annual Refining Survey," Oil and Gas Journal, various issues, 1970-1984.

TABLE B.31

UNION REFINERY CONFIGURATION
LEMONT, ILLINOIS
1970-1984

	1970	1975	1980	1981	1982	1983	1984
Crude Capacity							
m^3/cd	21 463	23 848	24 007	24 007	24 007	24 007	24 007
m^3/sd	NR	NR	24 961	24 961	24 961	24 961	24 961
Charge Capacity (m^3/sd)							
Vacuum Distillation	8 744	8 744	8 744	8 744	8 744	8 744	8 744
Thermal Operations	2 703	3 100	3 339	3 339	3 498	3 498	3 498
Cat Cracking							
Fresh Feed	7 154	8 585	9 221	9 221	9 221	8 426	9 221
Recycle	4 976	1 272	795	795	795	795	795
Cat Reforming	4 929	4 976	4 929	4 929	4 849	4 849	4 849
Cat Hydro Cracking	-	-	-	-	-	-	-
Cat Hydro Refining	2 544	2 464	-	-	-	-	-
Cat Hydro Treating	11 765	12 004	13 705	14 023	13 954	13 959	13 959
Production Capacity (m^3/sd)							
Alkylation Polymerization	2 544	2 464	2 385	2 385	2 385	2 385	2 385
Aromatics/Isomerization	509	461	556	556	556	556	556
Lubes	-	-	-	-	-	-	-
Asphalt	-	413	509	429	191	302	336
Hydrogen ($10^3 m^3$/d)	-	-	-	-	-	-	-
Coke (tonnes/d)	107	107	113	113	118	118	118

LEGEND: m^3/cd = cubic metres per calendar day m^3/sd = cubic metres per stream day

SOURCE: "Annual Refining Survey," Oil and Gas Journal, various issues, 1970-1984.

TABLE B.32

SUN REFINERY CONFIGURATION
TOLEDO, OHIO
1970-1984

	1970	1975	1980	1981	1982	1983	1984
Crude Capacity							
m^3/cd	17 807	19 873	19 873	19 873	19 873	18 760	18 760
m^3/sd	19 078	20 668	20 668	20 668	20 668	19 714	19 714
Charge Capacity (m^3/sd)							
Vacuum Distillation	3 498	3 498	3 498	3 498	3 498	3 498	3 498
Thermal Operations	-	-	-	-	-	-	-
Cat Cracking							
Fresh Feed	8 267	7 949	7 949	7 949	7 949	7 949	7 949
Recycle	2 862	1 192	1 192	1 192	1 192	1 192	1 192
Cat Reforming	6 646	6 518	6 518	6 518	6 518	6 518	6 518
Cat Hydro Cracking	3 816	4 134	4 134	4 134	4 134	4 134	4 134
Cat Hydro Refining	-	-	-	-	-	-	-
Cat Hydro Treating	7 472	4 372	4 372	4 372	4 372	4 372	4 372
Production Capacity (m^3/sd)							
Alkylation Polymerization	954	1 113	1 113	1 113	1 113	1 113	1 113
Aromatics/Isomerization	-	-	1 733	1 733	1 733	1 733	1 733
Lubes	-	-	-	-	-	-	-
Asphalt	-	-	-	-	-	-	-
Hydrogen ($10^3 m^3$/d)	-	-	-	1 359	1 359	1 359	1 359
Coke (tonnes/d)	-	-	-	-	-	-	-

LEGEND: m^3/cd = cubic metres per calendar day m^3/sd = cubic metres per stream day

SOURCE: "Annual Refining Survey," Oil and Gas Journal, various issues, 1970-1984.

TABLE B.33

MURPHY REFINERY CONFIGURATION
SUPERIOR, WISCONSIN
1970-1984

	1970	1975	1980	1981	1982	1983	1984
Crude Capacity							
m^3/cd	4 134	7 154	6 359	6 359	6 359	6 359	6 200
m^3/sd	4 452	7 441	7 441	7 441	7 441	6 677	6 359
Charge Capacity (m^3/sd)							
Vacuum Distillation	2 385	2 464	3 259	3 259	3 259	3 259	2 385
Thermal Operations	-	-	-	-	-	-	-
Cat Cracking							
Fresh Feed	1 272	1 542	1 542	1 542	1 542	1 542	1 510
Recycle	318	159	159	159	159	159	159
Cat Reforming	668	1 590	1 590	1 590	1 590	1 590	1 558
Cat Hydro Cracking	-	-	-	-	-	-	-
Cat Hydro Refining	1 463	922	922	922	922	922	-
Cat Hydro Treating	-	1 590	1 590	1 590	1 590	1 590	2 750
Production Capacity (m^3/sd)							
Alkylation Polymerization	191	191	270	270	270	270	254
Aromatics/Isomerization	-	-	-	-	-	-	-
Lubes	-	-	-	-	-	-	-
Asphalt	1 431	1 908	2 146	2 146	2 146	2 146	1 272
Hydrogen ($10^3 m^3$/d)	-	-	-	-	-	-	-
Coke (tonnes/d)	-	-	-	-	-	-	-

LEGEND: m^3/cd = cubic metres per calendar day m^3/sd = cubic metres per stream day

SOURCE: "Annual Refining Survey," Oil and Gas Journal, various issues, 1970-1984.

TABLE B.34

GLADIEUX REFINERY CONFIGURATION
FORT WAYNE, INDIANA
1970-1984

	1970	1975	1980	1981	1982	1983	1984
Crude Capacity							
m^3/cd	477	1 351	1 805	2 512	2 957	2 957	2 957
m^3/sd	NR	NR	1 940	2 703	3 180	3 180	3 180
Charge Capacity (m^3/sd)							
Vacuum Distillation	-	-	1 272	1 145	1 510	1 510	1 510
Thermal Operations	-	1 351	-	-	-	-	-
Cat Cracking							
Fresh Feed	-	-	-	-	-	-	-
Recycle	-	-	-	-	-	-	-
Cat Reforming	-	-	-	-	-	-	-
Cat Hydro Cracking	-	-	-	-	-	-	-
Cat Hydro Refining	-	-	-	-	-	-	-
Cat Hydro Treating	-	-	-	-	-	-	-
Production Capacity (m^3/sd)							
Alkylation Polymerization	-	-	-	-	-	-	-
Aromatics/Isomerization	-	-	-	-	-	-	-
Lubes	-	-	-	-	-	-	-
Asphalt	-	-	-	-	-	-	572
Hydrogen ($10^3 m^3$/d)	-	-	-	-	-	-	-
Coke (tonnes/d)	-	-	-	-	-	-	-

LEGEND: m^3/cd = cubic metres per calendar day m^3/sd = cubic metres per stream day

SOURCE: "Annual Refining Survey," Oil and Gas Journal, various issues, 1970-1984.

TABLE B.35

ASHLAND REFINERY CONFIGURATION
ST. PAUL PARK, MINNESOTA
1970-1984

	1970[a]	1975	1980	1981	1982	1983	1984
Crude Capacity							
m^3/cd	6 995	10 493	10 675	10 652	NR	NR	NR
m^3/sd	NR	10 811	10 970	10 970	10 970	10 970	11 005
Charge Capacity (m^3/sd)							
Vacuum Distillation	2 544	6 042	5 088	5 088	5 088	5 088	5 088
Thermal Operations	-	-	-	-	-	-	-
Cat Cracking							
Fresh Feed	1 908	3 339	3 657	3 657	3 657	3 657	3 657
Recycle	477	238	NR	NR	NR	NR	NR
Cat Reforming	1 590	1 590	2 067	2 067	2 067	2 067	2 067
Cat Hydro Cracking	-	-	-	-	-	-	-
Cat Hydro Refining	-	3 180	3 657	3 657	3 657	3 657	3 657
Cat Hydro Treating	2 385	2 385	3 212	3 371	4 483	4 483	4 483
Production Capacity (m^3/sd)							
Alkylation Polymerization	397	477	994	994	994	994	994
Aromatics/Isomerization	-	-	-	-	1 272	1 272	1 272
Lubes	-	-	-	-	-	-	-
Asphalt	1 431	3 498	2 226	2 226	2 226	2 226	2 226
Hydrogen ($10^3 m^3/d$)	-	-	-	-	-	-	-
Coke (tonnes/d)	-	-	-	-	-	-	-

LEGEND: m^3/cd = cubic metres per calendar day m^3/sd = cubic metres per stream day

SOURCE: "Annual Refining Survey," Oil and Gas Journal, various issues, 1970-1984.

[a] Northwestern Refining Co.

TABLE B.36

CAPACITY AND HEAVY CRUDE OIL NOMINATIONS OF CANADIAN REFINERIES NOMINATING FOR CANADIAN HEAVY CRUDE OIL
1983

	Refinery Capacity[a] (m^3/cd)	Average Monthly Nominations[b] (m^3/cd)	Number of Months Nominated	Total 1983 Nominations (10^3m^3)
British Columbia				
Chevron - Burnaby	5 560	214	8	52.1
Alberta				
Esso - Edmonton	24 100	1 197	12	436.9
Gulf - Calgary	2 050	1 136	11	380.1
Husky - Lloydminster	3 740	1 857	11	621.3
Saskatchewan				
Gulf - Moose Jaw	2 110	1 015	7	216.1
Ontario				
Esso - Sarnia	20 000	2 196	10	668.0
Gulf - Clarkson	9 540	812	12	296.4
Shell - Sarnia	11 765	-	-	-
Quebec				
Gulf - Montreal	9 220	-	-	-
Petro-Canada - Montreal	14 300	906	1	27.6
Shell - Montreal	19 078	-	-	-
TOTAL	121 463	7 393[c]	NA	2 698.4

SOURCES: (1) Alberta, Energy Resources Conservation Board, "Tabulation of Nominations and Estimated Requirements for Alberta Crude Oil and Pentanes Plus," Calgary, 1983 (Mimeographed); (2) Saskatchewan Energy and Mines, "Tabulation of Crude Oil Nominations and Estimated Requirements," Regina, 1983 (Mimeographed); and (3) Tables B.14 to B.25.

[a] m^3/cd = cubic metres per calendar day.

[b] Average total nominations by month.

[c] Total average monthly nominations for all eleven refineries weighted by the number of months in which nominations were made.

TABLE B.37

MONTHLY NOMINATIONS FOR CANADIAN HEAVY CRUDE OIL BY
CANADIAN REFINERIES NOMINATING FOR HEAVY CRUDE OIL
1983
(m^3/d)

	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Monthly Average
Alberta													
Heavy	5 454.0	6 369.9	5 449.1	2 260.0	8 560.1	10 756.4	11 624.0	10 649.1	10 454.7	11 788.1	9 882.0	6 550.0	8 316.5
Sask.													
Heavy	432.0	480.0	432.0	916.0	560.0	1 610.0	3 607.0	2 201.0	2 421.0	1 259.0	806.0	485.0	1 267.4
Medium[a]	1 100.0	1 100.0	1 100.0	500.0	938.0	477.0	2 645.0	2 807.0	2 923.0	3 681.0	2 000.0	1 500.0	1 730.9
TOTAL	6 986.0	7 949.9	6 981.1	3 676.0	10 058.1	12 843.3	17 876.0	15 657.1	15 798.7	16 728.1	12 688.0	8 535.0	11 314.8

SOURCES: (1) Alberta, Energy Resources Conservation Board, "Tabulation of Nominations and Estimated Requirements for Alberta Crude Oil and Pentanes Plus," Calgary, 1983 (Mimeographed); and (2) Saskatchewan Energy and Mines, "Tabulation of Crude Oil Nominations and Estimated Requirements," Regina, 1983 (Mimeographed).

[a] Saskatchewan medium crude oil includes crude oil less than or equal to 29° API and therefore is included in the definition of heavy crude oil used by this study.

TABLE B.38

TOTAL CANADIAN HEAVY CRUDE OIL DELIVERIES, AUTHORIZED EXPORTS, AND NOMINATIONS FOR SELECTED U.S. REFINERIES RECEIVING CANADIAN HEAVY CRUDE OIL

1980-1983
(m^3/d)

	1980	1981	1982	1983
Actual Deliveries	15 008	15 778	24 142	30 515
Authorized Exports	13 725	14 906	21 816	33 020
Nominations				
Alberta	-	4 231	6 782	12 824
Saskatchewan	-	11 431	13 799	19 015
Manitoba	-	-	58	51
Total Nominations	-	15 662	20 639	31 890
Total Refinery Capacity[a]	184 251	183 566	184 329	183 487

SOURCES: (1) Alberta, Energy Resources Conservation Board, "Tabulation of Nominations and Estimated Requirements for Alberta Crude Oil and Pentanes Plus," Calgary, 1980-1983 (Mimeographed); (2) American Petroleum Institute, Imported Crude Oil and Petroleum Products Reports (Database); (3) Canada, National Energy Board, "Memorandum to Applicants for Licensees to Export Crude Oil and Equivalent," File D1722-2, Ottawa, 1980-1983 (Mimeographed); and (4) Saskatchewan Energy and Mines, "Tabulation of Crude Oil Nominations and Estimated Requirements," Regina, 1980-1983 (Mimeographed).

[a] Total refinery crude charge capacity in cubic metres per calendar day, except Ashland capacity in cubic metres per stream day for 1982 and 1983.

TABLE 8.39

DELIVERIES OF CANADIAN HEAVY CRUDE OIL TO SELECTED U.S. REFINERIES[a]
1980-1984

Refinery, Location	1980		1981		1982		1983		1984[b]	
	10^3m^3/yr	Number Del.	10^3m^3/yr	Number Del.	10^3m^3/yr	Number Del.	10^3m^3/yr	Number Del.	10^3m^3/yr	Number Del.
Koch, Pine Bend										
Actual Del.	3 389.6	NR (NR)[c]	4 736.3	NR (NR)[c]	6 927.1	NR (NR)[c]	7 246.3	NR (NR)[c]	4 511.2	NR (NR)[c]
Auth. Imports	3 712.9	12	4 624.9	12	5 813.8	12	7 013.6	12	3 671.0	6
Nominations										
Alberta[d]	-	-	1 063.2	12	2 101.8	12	2 238.7	12	1 421.1	7
Sask.	-	-	3 001.1	12	3 619.0	12	3 955.9	12	2 390.6	7
Other	-	-	-	-	21.3	12	18.6	12	8.8	6
Total Nom.	-	-	4 064.3	24	4 996.9	36	5 915.1	36	3 820.5	20
Mobil, Joliet										
Actual Del.	1 134.9	NR (25.4)	550.0	NR (25)	1 084.8	NR (25)	1 367.2	NR (23)	961.4	NR (25)
Auth. Imports	393.1	8	483.4	9	1 050.5	12	1 335.0	12	747.4	6
Nominations										
Alberta	-	-	-	-	-	-	419.3	10	284.5	7
Sask.	-	-	554.4	12	574.7	12	852.2	12	596.4	7
Other	-	-	-	-	-	-	-	-	-	-
Total Nom.	-	-	554.4	12	574.7	12	1 271.5	22	880.9	14
Amoco, Whiting										
Actual Del.	-	- (NA)	-	- (NA)	170.9	NR (26)	813.3	NR (26)	410.7	NR (24)
Auth. Imports	17.1	3	-	-	-	-	-	-	165.6	2
Nominations										
Alberta	-	-	-	-	68.7	4	44.3	3	73.6	2
Sask.	-	-	-	-	-	-	604.6	12	300.2	7
Other	-	-	-	-	-	-	-	-	-	-
Total Nom.	-	-	-	-	68.7	4	648.9	15	373.8	9
Marathon, Detroit										
Actual Del.	5.2	NR (29)	-	- (NA)	28.9	NR (25)	764.5	NR (26)	436.7	NR (28)
Auth. Imports	7.8	4	-	-	-	-	765.7	12	320.0	5
Nominations										
Alberta	-	-	-	-	-	-	742.6	12	410.9	7
Sask.	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-
Total Nom.	-	-	-	-	-	-	742.6	12	410.9	7

Continued on Next Page

TABLE B.39 (Continued)

Refinery, Location	1980		1981		1982		1983		1984[b]	
	10^3m^3/yr	Number Del.	10^3m^3/yr	Number Del.	10^3m^3/yr	Number Del.	10^3m^3/yr	Number Del.	10^3m^3/yr	Number Del.
Union, Lemont										
Actual Del.	24.9	NR (27)	42.4	NR (25)	67.1	NR (24)	492.0	NR (24)	508.6	NR (26)
Auth. Exports	7.0	3	-	-	72.5	5	516.4	12	240.4	6
Nominations										
Alberta	-	-	-	-	-	-	-	-	-	-
Sask.	-	-	-	-	58.2	4	493.0	12	165.9	7
Other	-	-	-	-	-	-	-	-	-	-
Total Nom.	-	-	-	-	58.2	4	493.0	12	165.9	7
Murphy, Superior										
Actual Del.	295.7	NR (23)	273.0	NR (24)	290.8	NR (24)	254.5	NR (24)	172.3	NR (23)
Auth. Exports	267.4	10	274.3	12	290.0	12	290.1	12	147.6	6
Nominations										
Alberta	-	-	69.6	12	102.7	12	115.3	12	56.7	7
Sask.	-	-	179.7	12	139.3	12	138.4	12	78.6	7
Other	-	-	-	-	-	-	-	-	-	-
Total Nom.	-	-	249.3	24	242.0	24	253.7	24	135.3	14
Ashland, St. P.P.										
Actual Del.	428.1	NR (26)	125.0	NR (25)	151.8	NR (24)	102.9	NR (24)	59.9	NR (26)
Auth. Exports	495.4	9	-	-	125.7	8	108.8	6	26.4	3
Nominations										
Alberta	-	-	50.7	5	36.3	2	84.6	4	61.1	7
Sask.	-	-	85.0	5	43.3	3	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-
Total Nom.	-	-	135.7	10	79.6	5	84.6	4	61.1	7

SOURCES: (1) Alberta, Energy Resources Conservation Board, "Tabulation of Nominations and Estimated Requirements for Alberta Crude Oil and Pentanes Plus," Calgary, 1980-1983 (Mimeographed); (2) American Petroleum Institute, Imported Crude Oil and Petroleum Products Reports (Database); (3) Canada, National Energy Board, "Memorandum to Applicants for Licenses to Export Crude Oil and Equivalent," File 01722-2, Ottawa, 1980-1983 (Mimeographed); and (4) Saskatchewan Energy and Mines, "Tabulation of Crude Oil Nominations and Estimated Requirements," Regina, 1980-1983 (Mimeographed).

[a] Includes heavy crude oil less than or equal to 29° API.

[b] 1984 data for first 7 months only.

[c] Figure in parentheses is the average API gravity of all deliveries to the refinery in a given year. Data not reported for Koch refinery.

[d] 1982 and 1983 Alberta nominations by Koch include 745 200 and 298 100 cubic metres, respectively, of synthetic crude.

TABLE B.40

CANADIAN CRUDE OIL DELIVERIES, AUTHORIZED EXPORTS, AND NOMINATIONS
FOR KOCH REFINERY
PINE BEND, MINNESOTA
1983
(m^3/d)

	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	TOTAL[a]
Deliveries[b]	22 032	15 062	18 613	18 635	17 512	18 180	20 294	25 172	19 756	17 080	22 753	23 146	7 247
Authorized Exports[c]	19 070	19 070	17 481	17 481	17 481	17 481	18 772	25 876	19 070	19 070	19 070	20 670	7 014
Nominations:													
Alberta													
Heavy	6 400	5 400	4 400	4 700	4 500	4 700	5 600	5 300	5 400	5 100	6 200	6 100	1 941
Syn.	-	-	-	-	-	-	2 000	2 900	2 200	-	2 700	-	298
Sask.													
Heavy	5 540	6 770	7 040	6 480	6 190	3 920	5 300	4 330	6 700	7 770	5 520	7 710	2 229
Medium	4 840	4 640	3 640	2 452	4 952	7 252	4 652	5 052	4 852	3 652	5 252	5 552	1 727
Light	900	850	800	800	750	800	500	650	1 100	650	800	750	284
Manitoba													
Medium	60	60	60	48	48	48	48	48	48	48	48	48	19
Total Nominations	17 740	17 720	15 940	14 480	16 440	16 720	18 100	18 280	20 300	17 220	20 520	20 160	6 498

SOURCES: (1) Alberta, Energy Resources Conservation Board, "Tabulation of Nominations and Estimated Requirements for Alberta Crude Oil and Pentanes Plus," Calgary, 1983 (Mimeographed); (2) American Petroleum Institute, Imported Crude Oil and Petroleum Products Reports (Database); (3) Canada, National Energy Board, "Memorandum to Applicants for Licenses to Export Crude Oil and Equivalent," File D1722-2, Ottawa, 1983 (Mimeographed); and (4) Saskatchewan Energy and Mines, "Tabulation of Crude Oil Nominations and Estimated Requirements," Regina, 1983 (Mimeographed).

[a] Total 1983 deliveries, authorized exports, and nominations in thousand cubic metres.

[b] Includes heavy crude oil less than or equal to 29° API.

[c] Heavy crude oil.

TABLE B.41

DELIVERIES OF CANADIAN HEAVY CRUDE OIL TO KOCH REFINERY
PINE BEND, MINNESOTA[a]
1980-1984
($10^3 m^3$)

	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	TOTAL
1980	372.0	330.7	260.8	370.8	383.2	273.0	277.4	15.9	207.4	218.9	354.8	524.7	3 589.6
1981	345.5	442.8	475.2	380.1	294.8	226.1	288.3	412.1	415.8	474.3	486.0	495.1	4 736.3
1982	563.5	498.9	519.3	536.0	611.4	563.6	711.8	672.6	605.8	552.9	529.3	562.0	6 927.1
1983	670.1	458.1	566.1	566.8	532.7	553.0	617.3	765.6	600.9	519.5	692.1	704.0	7 246.3
1984[b]	623.3	636.7	717.1	629.0	652.0	553.6	699.7	672.3	590.3	647.8	-	-	6 421.7

SOURCE: American Petroleum Institute, Imported Crude Oil and Petroleum Products Reports (Database).

[a] Includes heavy crude oil less than or equal to 29° API.
[b] 1984 data not available after October. 1984 total includes first ten months only.

TABLE 3.42

AUTHORIZED EXPORTS OF CANADIAN CRUDE OIL TO KOCH REFINERY PINE BEND, MINNESOTA[a] 1980–1984 ($10^3 m^3$)

	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	TOTAL
1980	411.3	320.2	325.8	379.4	357.5	284.3	176.8	133.1	261.0	241.7	362.5	459.2	3712.8
1981	531.7	491.5	419.5	395.2	313.3	257.0	249.4	331.3	304.0	368.5	435.5	456.0	4624.9
1982	541.4	562.1	417.2	290.0	483.4	432.3	531.7	531.7	531.7	428.8	531.7	531.7	5813.8
1983	580.1	580.1	531.7	531.7	531.7	531.7	571.0	787.1	580.0	580.1	580.1	628.4	7013.7
1984[b]	665.3	665.3	656.2	588.4	517.7	580.4	-	-	-	-	-	-	3673.3

SOURCE: Canada, National Energy Board, "Memorandum to Applicants for Licenses to Export Crude Oil and Equivalent," File D1722-2, Ottawa, 1980-1984 (Mimeographed).

[a] Monthly figures based on daily figures multiplied by 365/12 (i.e., $m^3/d \times 365/12 = m^3/month$).

[b] 1984 data not available after June. 1984 total includes first six months only.

TABLE B.43

NOMINATIONS OF CANADIAN CRUDE OIL BY KOCH REFINERY
PINE BEND, MINNESOTA[a]
1980-1984
(10^3m^3)

		Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	TOTAL
1981	Heavy	271.9	302.3	339.9	161.2	154.8	108.9	156.6	191.0	153.3	229.0	253.4	281.1	2 603.4
	Medium	136.9	118.6	150.9	144.7	126.5	114.5	93.8	97.0	120.9	114.9	108.9	133.2	1 460.8
	Light	-	-	-	-	-	-	10.6	-	-	10.6	16.7	9.1	47.0
	Synthetic	-	-	-	-	-	-	-	-	-	-	-	-	-
1982	Heavy	303.9	281.4	278.6	222.3	236.9	229.6	243.0	286.2	289.6	317.9	299.6	300.2	3 289.2
	Medium	197.7	179.6	70.0	70.0	7.1	149.0	200.8	149.0	152.1	173.4	179.5	179.5	1 707.7
	Light	7.6	10.6	10.6	13.7	10.6	16.7	10.6	10.6	9.1	10.6	16.7	16.7	144.1
	Synthetic	-	-	121.7	121.7	97.3	82.1	124.7	82.1	76.0	9.1	30.4	-	765.1
1983	Heavy	363.2	370.2	348.0	340.1	325.1	262.2	331.5	292.9	368.0	391.5	356.5	420.1	3 978.7
	Medium	149.0	143.0	112.5	76.0	152.1	222.0	143.0	155.1	149.0	112.5	161.2	170.3	1 744.3
	Light	27.4	25.8	24.3	24.3	22.8	24.3	15.2	19.8	33.5	19.8	24.3	22.8	284.3
	Synthetic	-	-	-	-	-	-	60.8	88.2	66.9	-	82.1	-	298.0
1984[b]	Heavy	400.6	492.2	378.4	355.6	319.1	291.4	-	-	-	-	-	-	2 237.3
	Medium	194.7	182.5	219.0	158.2	161.2	167.3	-	-	-	-	-	-	1 082.9
	Light	22.8	24.3	24.3	28.9	10.6	38.4	-	-	-	-	-	-	149.3
	Synthetic	-	-	-	-	-	-	-	-	-	-	-	-	-

SOURCES: Alberta, Energy Resources Conservation Board, "Tabulation of Nominations and Estimated Requirements for Alberta Crude Oil and Pentanes Plus," Calgary, 1981-1984 (Mimeographed); and (2) Saskatchewan Energy and Mines, "Tabulation of Crude Oil Nominations and Estimated Requirements," Regina, 1981-1984 (Mimeographed).

[a] Monthly figures based on daily figures multiplied by 365/12 (i.e., $m^3/d \times 365/12 = m^3/month$).

[b] 1984 data not available after June. 1984 total includes first six months only.

TABLE B.44

CANADIAN CRUDE OIL DELIVERIES, AUTHORIZED EXPORTS, AND NOMINATIONS
FOR MOBIL OIL REFINERY
JOLIET, ILLINOIS
1983
(m^3/d)

	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	TOTAL[a]
Deliveries[b]	3 340	3 596	4 505	3 687	3 160	3 569	3 758	3 721	4 537	4 653	3 422	3 000	1 367
Authorized Exports[c]	3 660	3 660	3 660	3 660	3 660	3 660	3 665	3 655	3 655	3 655	3 655	3 655	1 337
Nominations:													
Alberta													
Heavy	-	-	1 125	1 384	1 360	1 487	1 438	1 438	1 442	1 438	1 336	1 336	419
Sask.													
Heavy	-	-	813	738	1 079	1 080	1 045	1 045	1 050	1 045	890	890	294
Medium	1 500	1 510	3 448	3 392	4 222	4 082	3 943	3 587	3 772	3 850	4 257	4 244	558
Total Nominations	1 500	1 510	3 448	3 392	4 222	4 082	3 943	3 587	3 772	3 850	4 251	4 244	1 271

SOURCES: (1) Alberta, Energy Resources Conservation Board, "Tabulation of Nominations and Estimated Requirements for Alberta Crude Oil and Pentanes Plus," Calgary, 1983 (Mimeographed); (2) American Petroleum Institute, Imported Crude Oil and Petroleum Products Reports (Database); (3) Canada, National Energy Board, "Memorandum to Applicants for Licenses to Export Crude Oil and Equivalent," File D1722-2, Ottawa, 1983 (Mimeographed); and (4) Saskatchewan Energy and Mines, "Tabulation of Crude Oil Nominations and Estimated Requirements," Regina, 1983 (Mimeographed).

[a] Total 1983 deliveries, authorized exports, and nominations in thousand cubic metres.
[b] Includes heavy crude oil less than or equal to 29° API.
[c] Heavy crude oil.

TABLE B.45

CANADIAN CRUDE OIL DELIVERIES, AUTHORIZED EXPORTS, AND NOMINATIONS
FOR AMOCO REFINERY
WHITING, INDIANA
1983
(m^3/d)

	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	TOTAL[a]
Deliveries[b]	2 765	2 352	2 127	3 089	2 372	2 425	1 690	1 486	785	2 854	2 450	2 103	837
Authorized Exports[c]	-	-	-	-	-	-	-	-	-	-	-	-	-
Nominations:													
Alberta													
Heavy	-	-	345	650	461	-	-	-	-	-	-	-	44
Light	-	-	-	-	-	1 666	1 613	605	-	-	-	-	118
Synthetic	-	-	-	-	-	-	-	-	484	-	-	-	15
						1 666							
Sask.													
Heavy	770	2 067	2 000	1 333	1 677	1 733	1 806	1 290	1 333	2 000	1 933	1 933	605
Total Nominations	770	2 067	2 345	1 983	2 138	3 399	3 419	1 895	1 817	2 000	933	1 935	782

SOURCES: (1) Alberta, Energy Resources Conservation Board, "Tabulation of Nominations and Estimated Requirements for Alberta Crude Oil and Pentanes Plus," Calgary, 1983 (Mimeographed); (2) American Petroleum Institute, Imported Crude Oil and Petroleum Products Reports (Database); (3) Canada, National Energy Board, "Memorandum to Applicants for Licenses to Export Crude Oil and Equivalent," File D1722-2, Ottawa, 1983 (Mimeographed); and (4) Saskatchewan Energy and Mines, "Tabulation of Crude Oil Nominations and Estimated Requirements," Regina, 1983 (Mimeographed).

[a] Total 1983 deliveries, authorized exports, and nominations in thousand cubic metres.
[b] Includes heavy crude oil less than or equal to 29° API.
[c] Heavy crude oil.

APPENDIX C

CANADIAN HEAVY CRUDE OIL SUPPLY/DEMAND FORECAST DATA TABLES

TABLE C.1

COMPARISON OF FORECAST PRICING SCENARIOS[a]
1982-2000

Year	NEB	NEB	CPA	EMR[b]			Gulf	Husky	Imperial[c]	Petro-Canada
	Low Price	High Price		Low Price	High Price	Conservation				
1982	34.00	34.00	34.00	33.82	33.82	33.82	34.00	34.00	NR	NR
1983	28.30	28.30	28.25	30.26	30.26	30.26	29.00	28.10	NR	25.80
1984	26.50	26.50	26.75	29.01	29.01	29.01	29.00	26.19	28.90	25.20
1985	26.50	33.00	25.25	29.01	29.01	29.01	30.00	24.70	28.90	24.70
1986	26.50	38.00	25.50	29.01	29.01	29.01	32.70	24.70	28.90	25.00
1987	NR	NR	NR	30.17	30.77	30.17	35.80	NR	28.90	26.00
1990	26.50	40.00	28.00	33.94	36.74	33.94	47.22	24.70	32.50	29.00
1995	26.50	42.00	30.50	43.40	51.81	43.40	67.79	26.50	39.50	32.50
2000	26.50	44.00	NR	55.49	73.08	55.49	97.32	28.42	48.00	36.00

SOURCES: See List of Studies and Submissions at the end of the Appendix.

[a] 1982 $U.S./bbl for Saudi Light Crude (34° API), unless otherwise stated. Amoco expects the price to remain constant in real terms over the forecast period. Dome provides four scenarios using the current and an alternative fiscal regime, each under the NEB's low and high price scenarios. Shell expects the price to remain at the current level with a modest increase occurring in the 1990s to recover the 1982 (real) price. Texaco suggests that there will be an increase in energy prices, but does not provide specific data.

[b] EMR estimates Persian Gulf (f.o.b.) prices in what is assumed to be $1984 (U.S.).

[c] Imperial estimates Persian Gulf (f.o.b.) prices in $1984 (U.S.).

TABLE C.2

COMPARISON OF FORECAST REAL CANADIAN GNP GROWTH
1984-2000
(average percent change/yr)

	1984	1985	1986	1987	1988	1990	1995	2000
CPA	NR	3.0	3.0	3.0	3.0	3.0	3.0	NR
EMR	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Gulf	4.3	3.0	3.0	1.6	NR	3.1	2.9	2.9
Husky	4.0	4.5	4.0	3.5	3.0	3.0	3.0	3.0
Imperial	2.8	2.8	2.8	2.8	2.8	2.5	2.5	2.5
Petro-Canada	5.0	>3.0	>3.0	>3.0	>3.0	>3.0	>3.0	>3.0
Total Average[a]	3.8	3.2	3.1	2.8	3.0	2.9	2.9	2.9
NEB	4.5	4.5	4.5	4.5	4.5	3.0	3.0	3.0

SOURCES: See List of Studies and Submissions at the end of the Appendix.

[a] Average excludes NEB data.

TABLE C.3

COMPARISON OF FORECAST PRODUCTIVE CAPACITY OF CANADIAN CONVENTIONAL HEAVY CRUDE OIL

1983-2000

($10^3 m^3/d$)

Year	CPA[a]	Dome		Nova/ Husky	Petro-Canada		Shell	Total Average[c]	NEB[d]
	Low Case	Low Price[b]	High Price[b]	Base Case	Low Case	High Case	Low Case		
1983	23.7	13.6	13.6	12.1	33.0	33.0	NR	20.6	34.3
1984	24.2	13.6	14.5	12.0	35.0	35.0	33.4	23.6	37.6
1985	24.0	13.1	14.5	12.7	37.0	37.0	30.2	23.4	36.5
1986	23.7	12.9	14.9	13.8	35.0	36.0	28.2	22.7	34.2
1987	23.5	12.7	15.1	14.5	34.0	37.0	26.1	22.2	32.5
1988	24.6	11.9	15.1	14.5	33.0	38.0	24.2	21.6	31.1
1989	24.8	11.4	15.3	13.8	31.0	37.0	22.7	20.7	30.1
1990	25.6	10.6	15.6	13.5	29.0	35.0	21.0	19.9	29.4
1991	26.4	9.9	15.7	12.0	26.0	33.0	19.4	18.7	28.7
1992	27.3	9.6	15.8	11.4	25.0	32.0	17.9	18.2	28.3
1993	27.8	9.2	15.9	10.4	23.0	30.0	17.1	17.5	27.9
1994	27.9	8.9	16.1	10.6	23.0	30.0	15.7	17.2	26.5
1995	27.5	8.6	16.3	10.2	21.0	29.0	14.7	16.4	27.1
1996	NR	8.3	16.5	9.9	20.0	28.0	14.6	13.2	26.8
1997	NR	8.0	16.5	9.8	19.0	27.0	13.8	12.7	26.6
1998	NR	7.8	16.5	9.4	18.0	26.0	13.8	12.3	26.2
1999	NR	7.3	16.7	9.0	18.0	27.0	13.0	11.8	25.8
2000	NR	7.2	16.5	8.7	17.0	26.0	12.7	11.4	25.6

SOURCES: See List of Studies and Submissions at the end of the Appendix.

[a] Derived from CPA Submission and additional information from CPA.

[b] Current fiscal regime.

[c] Average based on low and base cases only, and excludes NEB data.

[d] Productive capacity from remaining established reserves and reserves additions.

TABLE C.4

COMPARISON OF FORECAST PRODUCTIVE CAPACITY OF CANADIAN NON-CONVENTIONAL HEAVY CRUDE OIL
1983-2000
($10^3m^3/d$)

Year	CPA	Dome[a]		Gulf	Nova/ Husky	Petro-Canada		Total Average[b]	NEB[c]
	Low Case	Low Case	High Case			Low Case	High Case		
1983	28.6	29.4	29.4	27.0	27.4	28.0	28.0	28.1	27.5
1984	29.8	29.9	31.5	31.8	30.4	29.0	29.0	30.2	29.7
1985	31.6	30.4	34.4	33.4	32.4	33.0	33.0	32.2	32.0
1986	37.9	30.9	36.8	36.5	37.0	36.0	37.0	35.7	34.0
1987	40.7	31.3	39.6	38.1	39.3	37.0	39.0	37.3	36.0
1988	46.5	33.7	45.2	38.1	42.0	40.0	42.0	40.1	44.5
1989	52.1	34.0	48.7	38.1	44.4	40.0	45.0	41.7	41.5
1990	57.6	34.1	52.4	42.9	46.3	42.0	49.0	44.6	59.5
1991	60.1	34.2	56.4	42.9	47.1	42.0	55.0	45.3	62.5
1992	60.1	34.2	67.7	42.9	47.5	43.0	60.0	45.5	69.5
1993	60.1	34.2	69.6	42.9	50.5	43.0	63.0	46.1	76.5
1994	60.1	34.2	71.0	42.9	55.8	44.0	63.0	47.4	77.5
1995	60.1	34.2	71.9	52.4	58.3	44.0	67.0	49.8	78.5
1996	NR	34.2	72.0	52.4	60.8	44.0	71.0	47.9	79.5
1997	NR	34.2	72.0	52.4	63.6	44.0	74.0	48.9	80.5
1998	NR	34.2	82.8	52.4	68.6	45.0	74.0	50.1	81.5
1999	NR	34.2	84.2	52.4	70.8	45.0	77.0	50.6	87.5
2000	NR	34.2	84.2	57.2	72.7	45.0	80.0	52.3	93.5

SOURCE: See List of Studies and Submissions at the end of the Appendix.

[a] Current fiscal regime.
[b] Average based on low and base cases only, and excludes NEB data.
[c] Productive capacity of bitumen (including experimental) and synthetic crude.

TABLE C.5

COMPARISON OF FORECAST PRODUCTIVE CAPACITY OF TOTAL CANADIAN HEAVY CRUDE OIL

1983-2000
($10^3 m^3/d$)

Year	CPA	Dome[a]		Nova/Husky	Petro-Canada		Total Average[b]	NEB
	Low Case	Low Price	High Price	Base Case	Low Case	High Case		
1983	52.3	43.0	43.0	39.5	61.0	61.0	49.0	61.8
1984	54.0	43.5	46.0	42.4	64.0	64.0	51.0	67.3
1985	55.6	43.5	48.9	45.1	70.0	70.0	53.6	68.5
1986	61.6	43.8	51.7	50.8	71.0	73.0	56.8	68.2
1987	64.2	44.0	54.7	53.8	71.0	76.0	58.3	68.5
1988	71.1	45.6	60.3	56.5	73.0	80.0	61.6	75.6
1989	76.9	45.4	64.0	58.2	71.0	82.0	62.9	71.6
1990	83.2	44.7	68.0	59.8	71.0	84.0	64.7	88.9
1991	86.5	44.1	72.1	59.1	68.0	88.0	64.4	91.2
1992	87.4	43.8	83.5	58.9	68.0	92.0	64.5	97.8
1993	87.9	43.4	85.5	60.9	66.0	93.0	64.6	104.4
1994	88.0	43.1	87.1	66.4	67.0	93.0	66.1	104.0
1995	87.6	42.8	88.2	68.5	65.0	96.0	66.0	105.6
1996	NR	42.5	88.5	70.7	64.0	99.0	59.1	106.3
1997	NR	42.2	88.5	73.4	63.0	101.0	59.5	107.1
1998	NR	42.0	99.3	78.0	63.0	100.0	61.0	107.7
1999	NR	41.5	100.9	79.8	63.0	104.0	61.4	113.3
2000	NR	41.4	100.7	81.4	62.0	106.0	61.6	119.1

SOURCE: Tables C.3 and C.4.

[a] Current fiscal regime.
[b] Average based on low and base cases only, and excludes NEB data.

TABLE C.6

FORECAST RESERVES AND PRODUCTIVE CAPACITY OF ALBERTA CONVENTIONAL HEAVY CRUDE OIL AND SASKATCHEWAN HEAVY AND MEDIUM CRUDE OIL 1983-2000

Year	Alberta			Saskatchewan			Total Alberta and Saskatchewan Productive Capacity
	Total Remaining Recoverable Reserves	Total Productive Capacity		Total Remaining Recoverable Reserves	Total Productive Capacity		
	(10^3m^3)	(10^3m^3)	($10^3m^3/d$)	(10^3m^3)	(10^3m^3)	($10^3m^3/d$)	($10^3m^3/d$)
1983	37 363	5 840	16.0	71 280	6 707	18.4	34.4
1984	33 523	5 475	15.0	71 263	6 802	18.6	33.6
1985	30 048	5 110	14.0	71 981	6 905	18.9	32.9
1986	27 938	5 110	14.0	73 832	7 200	19.7	33.7
1987	25 828	4 745	13.0	75 695	7 315	20.0	33.0
1988	25 083	4 745	13.0	75 896	7 488	20.5	33.5
1989	24 338	4 325	12.0	75 502	7 625	20.9	32.9
1990	23 958	4 380	12.0	74 791	7 747	21.2	33.2
1991	22 578	4 380	12.0	73 758	7 858	21.5	33.5
1992	22 198	4 380	12.0	72 636	7 871	21.7	33.7
1993	21 818	4 380	12.0	70 813	7 929	21.7	33.7
1994	21 438	4 380	12.0	68 565	7 969	21.8	33.8
1995	21 058	4 380	12.0	66 474	7 908	21.7	33.7
1996	20 678	4 380	12.0	64 230	7 868	21.6	33.6
1997	20 298	4 380	12.0	61 802	7 707	21.1	33.1
1998	19 918	4 380	12.0	59 408	7 466	20.5	32.5
1999	19 538	4 015	11.0	57 084	7 298	20.0	31.0
2000	19 523	4 015	11.0	54 766	7 149	19.6	30.6

SOURCES: (1) Alberta, Energy Resources Conservation Board, *Alberta Oil Supply 1983-2007*, Report 83-E (Calgary: Energy Resources Conservation Board, 1983), Tables 3-1 and 3-2; (2) Alberta, Energy Resources Conservation Board, *Alberta's Reserves of Crude Oil, Gas, Natural Gas Liquids, and Sulphur*, Report 83-18 (Calgary: Energy Resources Conservation Board, 1983), Table 2-4; (3) Saskatchewan Department of Energy and Mines, "Submission to the National Energy Board by the Saskatchewan Department of Energy and Mines," Miscellaneous Report 84-5, January 1984, Table VII-A; and (4) Table C.7.

TABLE C.7

FORECAST PRODUCTIVE CAPACITY OF AND NET CHANGE IN ALBERTA CONVENTIONAL HEAVY CRUDE OIL REMAINING ESTABLISHED RESERVES
1983-2000
(10^3m^3)

Year	Remaining Recoverable Reserves as of Jan. 1	Reserves Added			Productive Capacity[a]			Net Decline in Reserves
		Discoveries/ Additions	Tertiary	Total Reserves Added	Established Reserves	Reserves Added and Tertiary	Total Productive Capacity	
1983	37 363	NR	NR	NR	5 840	-	5 840	3 840
1984	33 523	2 000	-	2 000	5 110	365	5 475	3 475
1985	30 048	2 000	1 000	3 000	4 745	365	5 110	2 110
1986	27 938	2 000	1 000	3 000	4 015	1 095	5 110	2 110
1987	25 828	2 000	2 000	4 000	3 650	1 095	4 745	745
1988	25 083	2 000	2 000	4 000	2 920	1 825	4 745	745
1989	24 338	2 000	2 000	4 000	2 555	1 825	4 380	325
1990	23 958	1 000	2 000	3 000	2 190	2 190	4 380	380
1991	22 578	1 000	3 000	4 000	2 190	2 190	4 380	380
1992	22 198	1 000	3 000	4 000	1 825	2 555	4 380	380
1993	21 818	1 000	3 000	4 000	1 825	2 555	4 380	380
1994	21 438	1 000	3 000	4 000	1 460	2 920	4 380	380
1995	21 058	1 000	3 000	4 000	1 095	3 285	4 380	380
1996	20 678	1 000	3 000	4 000	1 095	3 285	4 380	380
1997	20 298	1 000	3 000	4 000	1 095	3 285	4 380	380
1998	19 918	1 000	3 000	4 000	730	3 650	4 380	380
1999	19 538	1 000	3 000	4 000	365	3 650	4 015	15
2000	19 523	1 000	3 000	4 000	365	3 650	4 015	15

SOURCE: (1) Alberta, Energy Resources Conservation Board, Alberta Oil Supply 1983-2007, Report 83-E (Calgary: Energy Resources Conservation Board, 1983), Tables 3-1 and 3-2; and (2) Alberta, Energy Resources Conservation Board, Alberta's Reserves of Crude Oil, Gas, Natural Gas Liquids, and Sulphur, Report 83-18 (Calgary: Energy Resources Conservation Board, 1983), Table 2-4.

[a] Includes experimental schemes.

TABLE C.8

FORECAST TOTAL HEAVY CRUDE OIL SUPPLY--BASE CASE
1984-2000
($10^3 m^3$/d)

Year	Conventional		Alberta[c] Bitumen	Total Non-Synthetic	Synthetic		Total
	Alberta[a]	Sask.[b]			Suncor[d]	Syncrude[d]	
1984	15.0	18.6	5.2	38.8	13.3	23.1	75.2
1985	14.0	18.9	8.0	40.9	13.3	23.1	77.3
1986	14.0	19.7	13.0	46.7	13.3	23.1	83.1
1987	13.0	20.0	16.0	49.0	13.3	23.1	85.4
1988	13.0	20.5	16.0	49.5	13.3	23.1	85.9
1989	12.0	20.9	16.0	48.9	13.3	23.1	85.3
1990	12.0	21.2	16.0	49.2	13.3	23.1	85.6
1991	12.0	21.5	16.0	49.5	13.3	23.1	85.9
1992	12.0	21.7	16.0	49.7	13.3	23.1	86.1
1993	12.0	21.7	16.0	49.7	13.3	23.1	86.1
1994	12.0	21.8	16.0	49.8	13.3	23.1	86.2
1995	12.0	21.7	16.0	49.7	13.3	23.1	86.1
1996	12.0	21.6	16.0	49.6	13.3	23.1	86.0
1997	12.0	21.1	16.0	49.1	13.3	23.1	85.5
1998	12.0	20.5	16.0	48.5	13.3	23.1	84.9
1999	11.0	20.0	16.0	47.0	13.3	23.1	83.4
2000	11.0	19.6	16.0	46.6	13.3	23.1	83.0

SOURCE: (1) Alberta, Energy Resources Conservation Board, Alberta Oil Supply 1983-2007, Report 83-E (Calgary: Energy Resources Conservation Board, 1983), Tables 3-2 and 3-4; and (2) Saskatchewan Department of Energy and Mines, "Submission to the National Energy Board by the Saskatchewan Department of Energy and Mines," Miscellaneous Report 84-5, January 1984, Table VII-A.

[a] ERCB forecasts of conventional heavy crude oil productive capacity.

[b] Saskatchewan forecasts of heavy and medium crude oil productive capacity.

[c] ERCB forecasts of crude bitumen production until 1987, then held constant at the 1987 level for the rest of the period.

[d] Suncor and Syncrude synthetic crude oil production as measured in equivalent bitumen input units, and assuming maintenance of 100 percent of 1983 capacity.

TABLE C.9

FORECAST TOTAL HEAVY CRUDE OIL SUPPLY--LOW CASE
1984-2000
($10^3 m^3/d$)

Year	Conventional		Alberta[c] Bitumen	Total Non-Synthetic	Synthetic		Total
	Alberta[a]	Sask.[b]			Suncor[d]	Syncrude[d]	
1984	13.7	17.7	5.2	36.6	6.7	11.6	54.9
1985	13.0	16.8	8.0	37.8	6.7	11.6	56.1
1986	12.3	15.9	8.0	36.2	6.7	11.6	54.5
1987	11.7	15.1	8.0	34.8	6.7	11.6	53.1
1988	11.2	14.4	8.0	33.6	6.7	11.6	51.9
1989	10.6	13.7	8.0	32.3	6.7	11.6	50.6
1990	10.1	13.0	8.0	31.1	6.7	11.6	49.4
1991	9.5	12.3	8.0	29.8	6.7	11.6	48.1
1992	9.1	11.7	8.0	28.8	6.7	11.6	47.1
1993	8.6	11.1	8.0	27.7	6.7	11.6	46.0
1994	8.2	10.6	8.0	26.8	6.7	11.6	45.1
1995	7.7	10.1	8.0	25.8	6.7	11.6	44.1
1996	7.4	9.5	8.0	24.9	6.7	11.6	43.2
1997	7.0	9.1	8.0	24.1	6.7	11.6	42.4
1998	6.7	8.6	8.0	23.3	6.7	11.6	41.6
1999	6.4	8.2	8.0	22.6	6.7	11.6	40.9
2000	6.0	7.8	8.0	21.8	6.7	11.6	40.1

SOURCE: (1) Alberta, Energy Resources Conservation Board, Alberta Oil Supply 1983-2007, Report 83-E (Calgary: Energy Resources Conservation Board, 1983), Tables 3-2 and 3-4; and (2) Saskatchewan Department of Energy and Mines, "Submission to the National Energy Board by the Saskatchewan Department of Energy and Mines," Miscellaneous Report 84-5, January 1984, Table VII-A.

[a] ERCB forecasts of heavy crude oil productive capacity utilizing a 5 percent decline rate.

[b] Saskatchewan forecasts of heavy and medium crude oil productive capacity utilizing a 5 percent decline rate.

[c] ERCB forecasts of crude bitumen production held constant at 1985 level.

[d] Suncor and Syncrude synthetic crude oil production as measured in equivalent bitumen input units, and assuming 50 percent of 1983 capacity.

TABLE C.10

FORECAST TOTAL HEAVY CRUDE OIL SUPPLY--HIGH CASE
1984-2000
($10^3 m^3/d$)

Year	Conventional		Alberta Bitumen[c]	Total Non-Synthetic	Synthetic			Total
	Alberta[a]	Sask.[b]			Suncor[d]	Syncrude[d]	Petro-Canada[e]	
1984	16.0	18.6	5.2	39.8	13.3	23.1	-	76.2
1985	16.0	18.9	8.0	42.9	13.3	23.1	-	79.3
1986	16.0	19.7	13.0	48.7	13.3	23.1	-	85.1
1987	16.0	20.0	16.0	52.0	13.3	23.1	-	88.4
1988	16.0	20.5	21.0	57.5	13.3	27.3	-	98.1
1989	16.0	20.9	22.0	58.9	13.3	27.3	-	99.5
1990	16.0	21.2	23.0	60.2	13.3	27.3	-	100.8
1991	16.0	21.5	29.0	66.5	16.0	27.3	-	109.8
1992	16.0	21.7	33.0	70.7	16.0	27.3	11.0	125.0
1993	16.0	21.7	38.0	75.7	16.0	27.3	11.0	130.0
1994	16.0	21.8	42.0	79.8	16.0	38.7	11.0	145.5
1995	16.0	21.8	48.0	85.8	16.0	38.7	11.0	151.5
1996	16.0	21.8	52.0	89.8	16.0	38.7	11.0	155.5
1997	16.0	21.8	54.0	96.8	16.0	38.7	22.0	168.5
1998	16.0	21.8	56.0	93.8	16.0	38.7	22.0	170.5
1999	16.0	21.8	56.0	93.8	16.0	38.7	22.0	170.5
2000	16.0	21.8	76.0	113.8	16.0	38.7	22.0	190.5

SOURCE: (1) Alberta, Energy Resources Conservation Board, Alberta Oil Supply 1983-2007, Report 83-E (Calgary: Energy Resources Conservation Board, 1983), Tables 3-2 and 3-4; and (2) Saskatchewan Department of Energy and Mines, "Submission to the National Energy Board by the Saskatchewan Department of Energy and Mines," Miscellaneous Report 84-5, January 1984, Table VII-A.

[a] ERCB forecast of conventional heavy crude oil productive capacity utilizing a zero percent decline rate (i.e., maintaining constant supply).

[b] Saskatchewan forecast of heavy and medium crude oil productive capacity until 1994, then held constant at 1994 level for the rest of the period.

[c] ERCB forecast of crude bitumen production until 1990 but without the assumption of small scale upgraders such that from 1990 to 2000 approximately only 50 percent of the forecast volumes are included.

[d] Suncor and Syncrude synthetic crude production as measured in equivalent bitumen input units.

[e] Production from one Petro-Canada oil sands plant plus one other potential plant as measured in equivalent bitumen input units.

TABLE C.11

COMPARISON OF FORECAST CANADIAN DEMAND FOR ASPHALT[a]
1982-2000
(10^3m^3/d)

Study or Submission	1982	1983	1984	1985	1990	1995	2000	Avg. Annual % Change 1983-2000[b]
Hycarb	6.7	7.8	NR	8.3	8.9	9.9	10.5	1.8
EMR - Base Case	NR	7.0	7.1	7.3	8.9	11.0	13.0	3.7
- Conservation Case	NR	7.0	7.1	7.3	7.1	8.1	9.9	2.1
Gulf	6.7	6.9	6.9	7.0	7.8	8.0	8.2	1.0
Texaco	6.7	7.0	6.9	6.9	7.2	7.6	NR	0.7
Imperial	6.6	6.9	6.7	6.8	6.6	6.3	6.0	(0.8)
Shell - Base Case	6.7	6.3	6.4	6.6	7.4	8.1	8.7	1.9
- Alternative Case	6.7	6.3	6.4	6.7	7.9	8.6	9.0	2.1
Petro-Canada - Base Case	6.7	6.6	7.1	8.0	10.9	13.3	15.8	5.3
Total Average[c]	6.7	6.9	6.8	7.2	6.3	9.0	10.1	2.3

SOURCES: See List of Studies and Submissions at the end of the Appendix.

[a] Includes both roofing and paving demands and all penetration levels of asphalt.

[b] The Texaco average annual percentage change is calculated from 1983 to 1995 as a figure for 2000 is not given.

[c] Average based on base cases only.

TABLE C.12

COMPARISON OF FORECAST CANADIAN DEMAND FOR HEAVY FUEL OIL[a]
1982-2000
(10^3m^3/d)

Study or Submission	1982	1983	1984	1985	1990	1995	2000	Avg. Annual % Change 1983-2000[b]
Hycarb[c]	NR	NR	NR	26.4	17.3	14.6	13.9	(4.2)
EMR Base Case	28.3	22.0	23.2	24.2	23.6	24.4	22.4	0.1
Gulf	28.4	22.4	20.6	19.7	15.8	13.5	12.5	(3.4)
Texaco	23.3	25.5	25.3	23.5	17.8	16.1	NR	(3.8)
Imperial[d]	28.3	21.8	19.1	17.9	16.5	11.4	10.0	(4.5)
Shell								
Base Case	27.8	25.2	24.7	23.5	23.2	19.7	19.0	(1.6)
Alternative Case	27.8	25.2	24.7	24.5	23.8	20.2	19.3	(1.6)
Petro-Canada								
Base Case	29.1	24.0	23.8	23.2	17.4	13.3	11.4	(4.3)
Total Average[e]	27.5	23.5	22.8	22.6	18.8	14.4	14.9	(2.6)

SOURCES: See List of Studies and Submissions at the end of the Appendix.

[a] Figures are based on a combination of demand for heavy fuel oil by various sectors, namely the residential, commercial, industrial, transportation, and electric power generation sectors of the economy. See Table C.13 for a breakdown by these sectors.

[b] The Hycarb average annual percentage change calculated from 1985 to 2000 as a figure for 1983 is not given. The Texaco figure is calculated from 1983 to 1995 as a figure for 2000 is not given.

[c] Hycarb's figures for refinery consumption are not included.

[d] Imperial's figures for "own uses and losses" demand for heavy fuel oil are not included.

[e] Average based on base cases only.

TABLE C.13

COMPARISON OF FORECAST CANADIAN DEMAND FOR HEAVY FUEL OIL BY SECTOR
1982-2000
($10^3m^3/d$)

Study or Submission		1982	1983	1984	1985	1986	1987	1990	1995	2000
Hycarb										
Residential		NR	NR	NR	0.49	NR	NR	0.40	0.40	0.40
Commercial		NR	NR	NR	2.99	NR	NR	2.10	0.89	0.70
Industrial		NR	NR	NR	13.69	NR	NR	8.00	5.90	4.69
Transportation		NR	NR	NR	6.09	NR	NR	6.49	7.09	7.79
Electrical Generation		NR	NR	NR	3.10	NR	NR	0.29	0.29	0.29
Refinery Consumption		NR	NR	NR	3.59	NR	NR	3.29	3.19	3.29
Total		NR	NR	NR	29.95	NR	NR	20.57	17.76	17.16
EMR Base Case										
Residential & Agriculture		0.36	0.50	0.43	0.30	0.22	0.17	0.13	0.10	0.14
Commercial		3.23	2.57	2.46	2.27	2.15	2.11	1.93	1.89	1.77
Industrial		14.48	11.44	11.44	10.80	10.35	10.65	10.84	10.88	8.00
Transportation		4.89	3.85	4.67	5.79	6.03	6.19	6.58	7.29	7.21
Conversion Requirements:	Utilities	4.51	2.75	3.15	3.98	3.76	3.29	2.85	3.13	4.20
	Industry	0.30	0.26	0.29	0.31	0.31	0.31	0.31	0.26	0.26
	Steam	0.56	0.59	0.73	0.75	0.77	0.82	0.93	0.84	0.82
Total		28.33	21.96	23.17	24.20	23.59	23.54	23.57	24.39	22.40
Husky										
Industrial		10.83	11.29	11.69	11.95	11.36	11.75	11.62	11.49	11.36
Electrical Generation		3.41	4.07	3.68	3.81	3.54	3.74	3.74	3.74	3.74
Total		14.24	15.36	15.37	15.76	14.90	15.49	15.36	15.23	15.10

Continued on Next Page

TABLE C.13 (Continued)

Study or Submission	1982	1983	1984	1985	1986	1987	1990	1995	2000
Gulf									
Residential	0.27	0.22	0.20	0.17	0.17	0.17	0.15	0.14	0.12
Commercial	3.43	2.73	2.34	2.06	2.06	1.88	1.67	1.45	1.23
Industrial	15.04	12.56	11.70	10.72	10.18	9.58	7.71	5.88	4.93
Transportation	4.89	3.30	3.30	4.05	4.10	4.12	4.32	4.60	5.04
Electrical Generation	4.81	3.64	3.08	2.70	2.71	2.47	1.94	1.46	1.11
Total	28.44	22.45	20.62	19.70	19.22	18.22	15.77	13.53	12.43
Imperial									
Residential	0.32	0.39	0.32	0.32	0.32	0.32	0.20	0.20	0.20
Commercial	3.22	3.35	3.15	2.88	2.82	2.76	2.30	1.84	1.51
Industrial	15.36	11.09	9.85	9.51	9.26	9.26	8.53	5.19	4.40
Transportation	4.86	3.81	3.94	4.00	4.07	4.07	4.00	3.61	3.35
Electrical Generation	4.53	3.15	1.84	1.44	1.44	1.44	1.44	0.59	0.52
Own Uses & Losses	3.87	3.74	3.61	3.41	3.35	3.22	2.95	2.49	2.43
Total	32.16	25.53	22.71	21.56	21.26	21.07	19.42	13.92	12.41
Shell Base Case									
Residential	0.26	0.23	0.20	0.16	0.15	0.14	0.09	0.05	0.03
Commercial	3.26	3.32	3.02	2.79	2.70	2.62	2.38	2.16	2.00
Industrial	13.88	12.63	12.05	10.97	11.00	11.00	11.11	10.18	9.64
Transportation	4.89	4.98	5.05	5.07	5.32	5.32	5.34	5.57	5.80
Electrical Generation	5.55	4.07	4.40	4.47	4.37	4.30	4.24	1.79	1.58
Total	27.84	25.23	24.72	23.46	23.54	23.38	23.16	19.75	19.05
Shell Alternative Case									
Residential	0.26	0.23	0.20	0.16	0.15	0.14	0.09	0.05	0.03
Commercial	3.26	3.32	3.02	2.88	2.80	2.74	2.55	2.28	2.09
Industrial	13.88	12.63	12.05	11.67	11.59	11.53	11.38	10.37	9.57

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TABLE C.13 (Continued)

Study or Submission	1982	1983	1984	1985	1986	1987	1990	1995	2000
Shell Alternative Case (Continued)									
Transportation	4.89	4.98	5.07	5.28	5.46	5.47	5.51	5.76	6.02
Electrical Generation	5.55	4.07	4.40	4.47	4.37	4.30	4.24	1.79	1.58
Total	27.84	25.23	24.72	24.46	24.37	24.18	23.77	20.25	19.29
Petro-Canada									
Residential	0.29	0.32	0.33	0.34	0.35	0.35	0.34	0.27	0.21
Commercial	3.28	2.35	2.10	1.79	1.56	1.33	0.70	0.69	0.58
Industrial	14.63	11.23	11.39	11.21	10.87	10.36	8.42	5.83	4.17
Transportation	4.93	4.12	4.30	4.42	4.38	4.29	4.12	3.86	3.74
Electrical Generation	5.93	5.96	5.73	5.46	5.43	3.98	3.81	2.64	2.75
Total	29.06	23.98	23.85	23.23	22.59	20.31	17.37	13.30	11.44
Total Average[a]									
Residential	0.30	0.33	0.30	0.30	0.24	0.23	0.22	0.19	0.18
Commercial	3.28	2.86	2.61	2.46	2.26	2.14	1.85	1.49	1.30
Industrial	14.04	11.71	11.35	11.26	10.50	10.43	9.46	7.91	6.74
Transportation	4.89	4.01	4.25	4.90	4.78	4.80	5.14	5.34	5.49
Electrical Generation	4.93	4.08	3.82	3.72	3.72	3.39	2.79	2.11	2.18
Total	29.17	23.83	23.01	23.68	22.04	21.30	19.98	17.11	15.82
NEB									
Total	32.04	24.66	24.41	24.08	21.72	23.07	23.35	17.09	17.85

SOURCES: See List of Studies and Submissions at the end of the Appendix.

[a] Average based on base case only, and excludes NEB data. Average of total excludes Husky data as it is incomplete.

TABLE C.14

COMPARISON OF FORECAST CANADIAN DEMAND FOR HEAVY PETROLEUM PRODUCTS

1982-2000

($10^3m^3/d$)

Study or Submission	1982	1983	1984	1985	1986	1987	1990	1995	2000
EMR Base Case									
Lubes & greases	2.42	2.43	2.43	2.46	2.51	2.57	2.82	3.26	3.68
Naphtha specialties	1.06	1.07	1.56	1.63	1.80	2.01	2.59	3.71	4.75
Petrochemical feedstocks	8.78	7.60	7.64	7.10	5.64	5.79	6.13	6.56	6.96
Petroleum coke	1.60	1.67	1.79	1.84	1.87	1.96	2.18	2.64	3.06
Other miscellaneous products	1.33	0.83	0.89	0.91	0.93	0.97	1.09	1.32	1.54
Total	15.19	13.60	14.31	13.94	12.75	13.30	14.81	17.49	19.99
Gulf									
Lubes & greases	2.41	2.44	2.53	2.60	2.65	2.69	2.87	3.17	3.50
Naphtha specialties	1.07	1.13	1.18	1.25	1.29	1.32	1.44	1.65	1.88
Petrochemical feedstocks	8.79	8.81	9.25	10.63	10.81	10.98	14.07	15.45	16.84
Petroleum coke	1.84	1.88	2.05	2.23	2.58	2.65	2.72	2.72	2.72
Other miscellaneous products	1.33	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34
Total	15.44	15.60	16.35	18.05	18.67	18.98	22.44	24.33	26.28
Imperial[a]									
Lubes & greases	2.38	2.45	2.58	2.59	2.66	2.66	2.80	2.94	3.08
Petrochemical feedstocks	13.32	14.10	14.80	13.09	12.77	13.00	13.24	13.48	14.18
Other miscellaneous products	3.03	3.65	3.85	4.13	4.20	4.33	4.47	4.54	4.75
Own uses and losses	10.59	10.25	9.35	9.42	9.15	9.01	7.91	7.29	6.88
Total	29.32	30.45	30.58	29.23	28.78	29.00	28.42	28.25	28.89

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TABLE C.14 (Continued)

Study or Submission	1982	1983	1984	1985	1986	1987	1990	1995	2000
Shell Base Case									
Lubes & greases	2.43	2.43	2.50	2.62	2.74	2.79	3.00	3.30	3.77
Naphtha specialties	1.07	1.17	1.17	1.18	1.18	1.18	1.18	1.18	1.19
Petrochemical feedstocks	8.78	9.43	11.16	10.92	11.20	11.48	12.35	13.11	13.95
Petroleum coke	1.84	1.96	1.97	1.97	1.97	1.97	1.97	1.97	1.97
Other miscellaneous products	1.30	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16
Total	15.42	16.15	17.96	17.85	18.25	18.58	19.66	20.72	22.04
Shell Alternative Case									
Lubes & greases	2.43	2.43	2.50	2.60	2.71	2.78	3.05	3.37	3.83
Naphtha specialties	1.07	1.17	1.17	1.17	1.18	1.18	1.18	1.18	1.19
Petrochemical feedstocks	8.78	9.43	11.16	10.93	11.20	11.48	12.35	13.11	13.95
Petroleum coke	1.84	1.96	1.97	1.97	1.97	1.97	1.97	1.97	1.97
Other miscellaneous products	1.30	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.16
Total	15.42	16.15	17.96	17.83	18.22	18.57	19.71	20.79	22.10
Texaco									
Lubes & greases	2.49	2.56	2.62	2.65	2.69	2.72	2.84	3.04	NR
Petrochemical feedstocks	9.60	9.86	9.86	11.25	11.44	11.63	12.22	13.27	NR
Total	12.09	12.42	12.48	14.00	14.13	14.35	15.06	16.31	NR
Total Average[b]									
Lubes and greases	1.95	2.46	2.52	2.56	2.65	2.69	2.87	3.14	3.51
Naphtha specialties	1.07	1.12	1.30	1.35	1.42	1.50	1.74	2.18	2.61
Petrochemical feedstocks	9.85	9.83	10.54	10.60	10.37	11.53	11.60	12.37	12.98
Petroleum coke	1.76	1.84	1.94	2.01	2.14	2.19	2.29	2.44	2.58
Other miscellaneous products	1.75	1.75	1.81	1.89	1.91	1.95	2.02	2.09	2.20
Total	16.20	16.39	17.46	17.41	17.33	17.71	19.36	20.88	22.58

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TABLE C.14 (Continued)

Study or Submission	1982	1983	1984	1985	1986	1987	1990	1995	2000
NEB									
Lubes and greases	2.42	2.51	2.60	2.69	2.78	2.87	3.14	3.59	4.04
Petrochemical feedstocks	9.02	8.26	8.54	9.82	8.14	6.45	6.44	6.45	6.47
Other miscellaneous products	14.29	13.73	13.73	13.67	13.44	13.37	13.43	13.78	14.64
Total	25.73	24.50	24.87	26.18	24.36	22.69	23.01	23.82	25.15

SOURCES: See List of Studies and Submissions at the end of the Appendix.

[a] "For the processing of crude oil-derived feedstocks, between 75 and 80 percent of the gross energy requirement is satisfied by petroleum products and approximately 88 percent of this comes from the feedstock itself." See Imperial Oil Ltd., "Canadian Petrochemical Industry Feedstock and Energy," Study prepared for the Canadian Chemical Producers' Association, 1980. This factor accounts for discrepancies between Statistics Canada and industry figures for petrochemical feedstock demand.

[b] Average based on base case only, and excludes NEB data. Average of total excludes Texaco data as it is incomplete, and Imperial "own uses and losses" data.

TABLE C.15

COMPARISON OF FORECAST CANADIAN REFINERY DEMAND FOR CANADIAN AND FOREIGN FEEDSTOCK

1982–2000

($10^3 m^3/d$)

	1982	1983	1984	1985	1986	1987	1990	1995	2000	Avg. Annual % Change 1983–2000[a]
Domestic Light & Equivalent Feedstock										
Gulf	NR	181.4	191.5	185.5	184.0	180.6	192.7	211.6	220.7	1.2
Imperial	168.2	174.2	176.8	169.5	144.1	140.1	140.7	165.2	156.8	(0.6)
Shell	177.1	177.3	175.3	164.9	156.4	145.3	120.7	114.2	150.4	(1.0)
Texaco	176.8	176.8	172.8	158.6	151.3	141.5	140.7	145.6	NR	(1.6)
Total Average[b]	174.0	177.4	179.1	169.6	169.6	151.9	148.7	159.2	176.0	—
NEB	177.6	177.9	169.7	163.3	158.3	53.9	148.7	179.7	171.2	(0.2)
Domestic Heavy Feedstock[c]										
EMR – Base Case	13.7	3.6	6.0	8.7	5.4	14.7	9.8	7.2	11.4	7.0
– High Price Case	13.7	3.6	6.0	8.7	5.4	14.7	7.5	7.6	14.9	9.5
Amoco – Base Case	NR	9.6	11.2	12.7	12.7	16.7	16.7	16.7	16.7	3.3
Foster	NR	NR	12.9	13.2	13.9	14.1	14.3	15.4	16.4	1.5
Gulf	NR	9.7	9.8	9.9	10.4	12.3	16.2	17.0	17.5	3.5
Hycarb	NR	9.5	NR	14.3	NR	NR	18.3	15.0	16.2	3.2
Imperial	14.7	11.3	12.5	11.8	13.1	13.1	12.2	16.4	16.6	2.3
Shell	14.7	11.1	15.7	16.0	16.2	16.5	13.4	15.0	16.6	2.4
Texaco	14.5	11.8	13.6	14.6	15.2	14.3	14.3	14.3	NR	1.6
Total Average[b]	14.6	10.5	12.6	13.2	13.6	14.5	17.6	15.7	16.7	2.8
NEB	14.7	11.3	15.1	15.8	16.2	16.7	17.8	19.4	20.8	3.7
Foreign Feedstock										
Gulf	54.7	37.5	27.7	32.6	34.7	35.4	17.4	2.9	2.9	(14.0)
Imperial	54.6	42.9	36.3	39.0	42.8	54.6	51.6	10.0	6.0	(10.9)
Shell[d]	44.7	35.9	27.9	28.6	38.1	48.9	76.3	87.0	53.1	2.3
Texaco	45.5	35.6	37.0	50.0	56.0	67.1	68.9	77.5	NR	6.7
Total Average[b]	49.9	38.0	32.2	37.6	42.9	51.5	53.6	44.4	20.7	(3.5)
NEB	45.0	34.9	30.0	28.8	28.2	27.9	26.1	NR	14.3	(5.1)

SOURCES: See List of Studies and Submissions at the end of the Appendix.

[a] The Texaco average annual percentage change is calculated from 1983 to 1995 as a figure for 2000 is not given.

[b] Average based on base case only, and excludes EMR and NEB data.

[c] Excludes upgrader and synthetic production demand. All industry forecasts except Amoco's are based on refinery feedstock demand for Canadian heavy crude oil derived from refined petroleum products demand. The EMR figures are derived by subtracting exports, net of the diluent component, from total refinery feedstock demand. The diluent component is estimated at 50 percent of pentanes plus production for that year. An EMR spokesman suggested estimating the diluent component as 10 percent of old conventional, old-new, EOR, and new conventional production plus 43 percent of experimental production. Because the former method, the method employed, yields low initial values, and the latter method suggested by EMR yields high values in later years, both are excluded from the averages.

[d] Excludes exchanges with the U.S. amounting to 9200 cubic metres per day in 1982.

TABLE C.16

COMPARISON OF FORECAST BREAKDOWN OF CANADIAN REFINERY DEMAND
FOR CANADIAN FEEDSTOCKS--ATLANTIC REGION
1982-2000
(10^3m^3/d)

Study or Submission	1982	1983	1984	1985	1986	1987	1990	1995	2000
Gulf									
Light & equivalent	3.8	8.4	8.0	3.0	NR	NR	10.5	18.6	18.9
Heavy	-	-	-	-	NR	NR	-	-	-
Imperial									
Light & equivalent	3.1	5.9	5.3	NR	NR	NR	NR	13.5	12.1
Heavy	NR	NR	NR	NR	NR	NR	NR	NR	NR
Texaco									
Light & equivalent	3.9	6.0	4.0	-	-	-	-	21.5	NR
Heavy	-	-	-	-	-	-	-	-	NR
Total Average[a]									
Light & equivalent	3.6	6.8	5.8	1.5	-	-	5.3	17.9	15.5
Heavy	-	-	-	-	-	-	-	-	-
NEB									
Crude oil & equivalent	23.0	22.7	23.1	21.9	21.2	20.9	19.1	19.2	20.3

SOURCES: See List of Studies and Submissions at the end of the Appendix.

[a] Average excludes NEB data.

TABLE C.17

COMPARISON OF FORECAST BREAKDOWN OF CANADIAN REFINERY DEMAND FOR CANADIAN FEEDSTOCKS--QUEBEC

1982-2000

($10^3 m^3/d$)

Study or Submission	1982	1983	1984	1985	1986	1987	1990	1995	2000
Gulf									
Light & equivalent	NR	36.6	36.3	34.4	35.3	32.4	36.3	41.3	41.4
Heavy	NR	1.1	1.1	1.2	1.3	3.0	7.2	7.6	7.6
Imperial									
Light & equivalent	32.9	32.6	31.8	32.4	25.1	12.0	12.2	29.8	30.4
Heavy	3.9	1.3	2.7	2.0	3.0	3.0	2.0	6.0	6.0
Texaco									
Light & equivalent	34.9	32.8	33.2	23.5	16.8	6.8	3.3	4.8	NR
Heavy	3.7	1.6	1.6	1.6	1.6	-	-	-	NR
Total Average[a]									
Light & equivalent	33.9	34.0	33.8	30.1	25.7	17.1	17.3	25.3	35.9
Heavy	3.8	1.3	1.8	1.6	2.0	2.0	4.6	6.8	6.8
NEB									
Crude oil & equivalent	66.5	55.1	54.0	49.0	47.7	46.1	44.2	45.4	46.5

SOURCES: See List of Studies and Submissions at the end of the Appendix.

[a] Average excludes NEB data.

TABLE C.18

COMPARISON OF FORECAST BREAKDOWN OF CANADIAN REFINERY DEMAND FOR CANADIAN FEEDSTOCKS--ONTARIO
1982-2000
($10^3 m^3/d$)

Study or Submission	1982	1983	1984	1985	1986	1987	1990	1995	2000
Gulf									
Light & equivalent	NR	70.8	81.5	80.6	80.3	79.8	74.5	75.8	78.2
Heavy	NR	3.5	3.4	3.2	3.4	3.4	2.8	2.8	2.8
Imperial									
Light & equivalent	61.8	68.4	71.4	68.4	65.1	63.8	60.2	52.4	49.1
Heavy	6.9	5.3	5.4	5.4	5.5	5.5	5.0	5.0	5.0
Texaco									
Light & equivalent	68.9	71.0	67.7	67.7	67.5	67.2	66.9	43.4	NR
Heavy	6.8	5.6	7.2	6.5	6.4	6.4	6.4	6.4	NR
Total Average[a]									
Light & equivalent	65.4	70.1	73.5	72.2	71.0	70.3	67.2	57.2	63.7
Heavy	6.9	4.8	5.3	5.0	5.1	5.1	4.7	4.7	3.9
NEB									
Crude oil & equivalent	77.0	78.5	70.5	71.2	68.8	67.0	65.2	67.8	67.8

SOURCES: See List of Studies and Submissions at the end of the Appendix.

[a] Average excludes NEB data.

TABLE C.19

COMPARISON OF FORECAST BREAKDOWN OF CANADIAN REFINERY DEMAND FOR CANADIAN FEEDSTOCKS--WESTERN REGION
1982-2000
($10^3 m^3/d$)

Study or Submission	1982	1983	1984	1985	1986	1987	1990	1995	2000
Gulf									
Light & equivalent - Prairies	NR	41.9	41.4	43.0	43.7	43.9	46.3	50.1	54.8
- BC, Yukon, NWT	NR	23.7	24.1	24.5	24.7	24.5	25.1	26.1	27.4
Total light & equivalent	NR	65.6	65.5	67.5	68.4	68.4	71.4	76.2	82.2
Heavy - Prairies	NR	5.1	5.3	5.5	5.7	5.9	6.2	6.6	7.1
Imperial									
Light & equivalent - Prairies	45.7	43.9	45.3	46.0	45.1	45.4	45.4	48.1	45.5
- BC, Yukon, NWT	24.7	23.4	23.0	22.8	22.8	22.9	22.3	21.4	19.6
Total light & equivalent	70.4	67.3	68.3	68.8	67.9	68.3	67.7	69.5	65.1
Texaco									
Light & equivalent	69.1	67.0	67.9	67.4	67.0	67.5	70.5	75.9	NR
Heavy	4.0	4.6	4.8	6.5	7.2	7.9	7.9	7.9	NR
Total Average[a]									
Light & equivalent	69.8	66.6	67.2	67.9	67.8	68.1	69.9	73.9	73.7
Heavy	4.0	4.9	5.1	6.0	6.5	6.9	7.1	7.8	7.1
NEB									
Crude oil & equivalent - Prairies, NWT	48.6	50.2	45.7	45.7	45.1	45.1	44.0	45.4	49.4
- BC, Yukon	25.0	22.9	23.5	22.2	22.0	21.6	22.4	23.4	24.7
Total crude oil & equivalent	73.6	73.1	69.2	67.9	67.1	66.7	66.4	68.8	74.1

SOURCES: See List of Studies and Submissions at the end of the Appendix.

[a] Average excludes NEB data. Average light & equivalent based on total light & equivalent.

TABLE C.20

COMPARISON OF FORECAST CANADIAN UPGRADER DEMAND FOR CANADIAN HEAVY CRUDE OIL
1987-2000
($10^3m^3/d$)

Study or Submission	1987	1988	1989	1990	1995	2000	Avg. Annual % Change 1987-2000[a]
Amoco	8.0	8.0	8.0	8.0	8.0	8.0	-
EMR							
Base Case	8.0	8.0	8.0	12.0	16.0	16.0	5.5
High Price Case	8.0	8.0	8.0	12.0	24.0	32.0	11.3
Foster	8.0	8.0	8.0	8.0	8.0	8.0	-
Husky	NR	NR	NR	7.9	7.9	7.9	-
Imperial	-	-	-	-	8.0	8.0	-
Petro-Canada							
Base Case	-	4.0	8.0	8.0	8.0	8.0	5.9
High Price Case	8.0	8.0	8.0	8.0	16.0	28.0	10.1
Total Average[b]	4.8	5.6	6.4	7.3	9.3	9.3	5.2
CERI Base Case[c]	8.0	8.0	8.0	16.0	24.0	24.0	8.8
NEB	-	8.0	15.0	15.0	15.0	15.0	5.4

SOURCES: See List of Studies and Submissions at the end of the Appendix.

[a] Average annual percentage change for Husky, Imperial, and the Petro-Canada base case and the NEB calculated from 1990, 1995, and 1988 to 2000, respectively, as figures for earlier years are not given or zero.

[b] Average based on base case only, and excludes CERI base case and NEB data.

[c] Assumes two upgraders by the end of the 1980s, plus an additional upgrader by the mid-1990s.

TABLE C.21

COMPARISON OF FORECAST CANADIAN DEMAND FOR CANADIAN HEAVY CRUDE OIL TO PRODUCE SYNTHETIC CRUDE OIL[a]

1982-2000

$(10^3 m^3/d)$

Study or Submission	1982	1983	1984	1985	1986	1987	1990	1995	2000	Avg. Annual % Change 1983-2000[b]
EMR										
Base Case	25.5	33.9	32.6	34.3	34.3	37.2	37.6	43.9	51.2	2.5
High Price Case	25.4	33.9	32.6	34.3	34.3	37.2	37.6	51.2	61.9	3.6
Gulf	NR	36.0	36.0	36.0	36.0	38.1	40.2	52.9	59.3	3.0
Husky	NR	32.8	35.2	36.0	36.8	37.3	38.5	50.0	66.6	4.3
Petro-Canada										
Base Case	NR	32.0	32.0	33.3	34.6	36.0	40.0	40.0	40.0	1.3
High Price Case	NR	32.0	32.0	33.3	34.6	36.0	42.6	50.6	57.3	3.5
CPA	NR	33.2	33.1	33.7	36.0	36.8	50.6	50.6	NR	3.6
Dome										
Low Price Case[c]	NR	34.9	35.6	36.3	36.9	37.5	41.2	41.3	41.3	1.0
High Price Case[c]	NR	34.9	35.6	36.3	36.9	37.5	41.2	56.1	72.4	4.4
Texaco	25.5	33.3	33.3	33.3	33.9	33.9	36.0	36.0	NR	0.7
Total Average[d]	25.5	33.7	34.0	34.7	35.5	36.7	40.6	45.0	51.7	2.5
NEB	NR	31.3	32.3	33.3	33.3	33.3	56.7	71.3	84.7	6.0

SOURCES: See List of Studies and Submissions at the end of the Appendix.

[a] All figures shown are converted from projected amounts of synthetic crudes produced from mineable oil sands by dividing synthetic output by 0.75. In situ production was excluded.

[b] The CPA and Texaco average annual percentage changes calculated from 1983 to 1995 as figures for 2000 are not given.

[c] Current fiscal regime.

[d] Average based on low and base cases only, and excludes NEB data.

TABLE C.22

COMPARISON OF FORECAST U.S. DEMAND FOR CANADIAN HEAVY CRUDE OIL[a]

1983-2000
($10^3 m^3/d$)

Study or Submission	1983	1984	1985	1986	1987	1990	1995	2000	Avg. Annual % Change 1983-2000[b]
APMC	30.0	35.0	35.0	43.0	45.0	22.0	40.0	37.0	1.2
Amoco									
Base Case	28.6	32.4	36.3	39.3	42.4	51.5	63.0	74.4	5.8
Improvement Case	28.6	34.0	38.1	43.2	46.6	56.7	69.3	81.8	6.4
Hycarb	31.6	NR	32.8	NR	NR	47.1	NR	47.1	2.4
EMR									
Base Case	34.6	35.3	32.8	34.4	24.6	30.7	37.7	34.3	(0.1)
High Price Case	34.6	35.3	32.8	34.4	24.6	33.0	37.3	30.8	(0.7)
Foster	NR	28.5	29.4	36.5	38.2	47.7	51.6	46.7	3.1
Shell	25.1	28.6	25.0	23.1	22.7	15.7	10.6	11.4	(4.5)
Total Average[c]	30.0	26.2	31.9	35.3	34.6	35.8	40.6	41.8	2.0
Net Total Average[d]	24.0	21.0	25.5	28.2	27.7	28.6	32.5	33.5	2.0

SOURCES: See List of Studies and Submissions at the end of the Appendix.

[a] All forecasts include condensate.

[b] The Foster average annual percentage change calculated from 1984 to 2000 as a figure for 1983 is not given.

[c] Average based on base case only.

[d] Total average less 20 percent for diluent component.

LIST OF STUDIES AND SUBMISSIONS

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(2) ________. Energy Resources Conservation Board. Alberta's Reserves of Crude Oil, Gas, Natural Gas Liquids, and Sulphur at December 31, 1982. Report 83-18. Calgary: Energy Resources Conservation Board, 1983.

(3) Alberta Petroleum Marketing Commission, "Submission to the National Energy Board of Canada 1984 Supply and Demand Update," January 16, 1984.

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(5) Canada. Department of Energy, Mines and Resources. "Long-Term Energy Supply/Demand Outlook: Spring 1984 Forecast." Ottawa: Energy, Mines and Resources Canada, 1984.

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(8) Dome Petroleum Limited. "Energy Update Supply/Demand Forecasts 1983-2005: Submission to the National Energy Board," January 1984.

(9) Foster Research. The Forecast Supply and Demand for Alberta Condensate for Blending with Heavy Crude Oil 1984-2000. Calgary: Foster Research, 1984.

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(11) Hycarb Engineering Ltd. Canadian Heavy Crude Oil Market Analysis. Calgary: Hycarb Engineering Ltd., 1984.

(12) Imperial Oil Limited, "Submission to the National Energy Board in the Matter of Canada's Long-Term Energy Supply and Demand," February 1984.

(13) Nova, An Alberta Corporation and Husky Oil Operations Ltd., "Update of Energy Supply and Demand 1983 to 2005: Submission to the National Energy Board," January 1984.

(14) PanCanadian Petroleum Limited. "Submission to the National Energy Board on Update of Energy Supply and Demand 1983 to 2005." January 1984.

(15) Petro-Canada, "Submission to the National Energy Board Update of Energy Supply and Demand, 1983 to 2005," January 1984.

(16) Saskatchewan Department of Energy and Mines, "Energy Supply and Demand," Miscellaneous Report 84-5, January 1984.

(17) Shell Canada Limited, "Submission to the National Energy Board Re: NEB Update to Energy Supply and Demand, 1983 to 2005," January 1984.

(18) Texaco Canada Inc., "Submission to the National Energy Board: Update of Energy Supply and Demand 1982-1995," February 1984.

APPENDIX D

CANADIAN PENETRATION OF THE UNITED STATES HEAVY CRUDE OIL MARKET: LOGISTICS AND DATA TABLES

Appendix D

CANADIAN PENETRATION OF THE UNITED STATES HEAVY CRUDE OIL MARKET: LOGISTICS AND DATA TABLES

D.1 Pipelining Canadian Heavy Crude Oil

The Interprovincial Pipeline (IPL) carries most of the Canadian heavy crude oil that is delivered to Canadian and U.S. refineries (see Figure 5.4). Since 1982, Cold Lake bitumen has been transported from Cold Lake to Edmonton (a distance of 240 kilometres) through a 4610 cubic metre per day pipeline owned by Alberta Energy Company. This is a dual line, including a diluent return pipe, and connects with the IPL and Trans-Mountain networks at Edmonton. Cold Lake bitumen is also trucked to Lloydminster crude oil gathering systems, although a pipeline may cover this distance in the near future.

A triple pipeline runs between Lloydminster and Hardisty; one for diluent, the others for shipping diluted Lloydminster crude oil and crude tops. Some Cold Lake crude oil and heavy Lindbergh crude oil are also handled by the system, received via truck and pipeline, respectively. Lloydminster crude oil is also delivered to the IPL system in Saskatchewan from Lloydminster, Saskatchewan.

Koch owns a pipeline system that gathers heavy and medium crude oils in southeastern Alberta and feeds into the IPL network at Hardisty. As production from southeastern Alberta eventually declines, this system may be reversed, allowing heavy crude oils to flow from Hardisty to Montana.

A southern Saskatchewan pipeline owned jointly by Mobil, Koch and Union Oil segregates light and heavy crude oils gathered in the southwest of that province and delivers them to the IPL line at Regina.

Smiley-Coleville heavy crude oil found in western Saskatchewan is transported by pipeline from fields north of Lloydminster to Kerrobert, Saskatchewan through the Bow River Pipe Line. Weyburn-Midale crude oil from southeastern Saskatchewan is delivered to IPL at Cromer, Manitoba through Dome's Westspur Pipeline.

All of the aforementioned heavy crude oils are carried by the IPL/Lakehead system in segregated batches in two separate lines. The minimum gravity accepted by IPL/Lakehead is 20° to 22° API, and the maximum viscosity is 220 centistokes (at 22° C). Crudes with specific gravity less than 25° API are charged a premium of 15 percent over light crude oil tariffs. Those of 25° to 30° API are transported at a 5 percent premium.

Canadian heavy crude oil could be delivered to refineries in the Chicago area, Ohio, and Warren, Pennsylvania via Sarnia, Ontario, and to Buffalo, New York through U.S. carriers that connect to the IPL/Lakehead network. In addition, Washington state refineries could have access to diluted Cold Lake bitumen through their connections to the Trans-Mountain pipeline system.

TABLE D.1

UNITED STATES CRUDE OIL SUPPLY AND DEMAND BALANCE[a]
1970-2000
($10^6 m^3$)

Year	Domestic Production[b]	Imports	Total Supply	Demand[b]	Excess Over Supply[c]
1970	559.2	76.7	635.9	854.1	294.9
1971	549.1	97.4	646.5	883.3	334.2
1972	549.4	128.8	678.2	949.0	399.6
1973	534.3	188.0	722.3	1 007.4	473.1
1974	509.2	201.5	711.7	949.0	439.8
1975	486.0	237.9	723.9	949.0	463.0
1976	473.2	307.3	780.5	1 014.7	541.5
1977	478.4	383.4	861.8	1 058.5	580.1
1978	505.3	368.4	873.7	1 095.0	589.7
1979	496.2	377.8	878.0	1 058.5	562.3
1980	500.2	305.9	803.3	985.5	485.3
1981	497.4	254.8	756.7	930.8	433.4
1982	501.9	202.2	705.9	887.0	385.1
1983	503.7	NR	NA	912.5	408.8
1984	503.7	NR	NA	912.5	408.8
1985	522.0	NR	NA	908.9	386.9
1990	511.0	NR	NA	912.5	401.5
1995	489.1	NR	NA	949.0	459.9
2000	478.2	NR	NA	865.0	386.8

SOURCES: (1) American Petroleum Institute, *Basic Petroleum Data Book*, Vol. IV, No. 1, January 1984 (Washington, D.C.: API, 1984), Section IV, Tables 4a and 4b, and Section IX, Table 3a; (2) U.S. Energy Information Administration, *Annual Energy Outlook 1983* (Washington, D.C.: U.S. Government Printing Office, 1984), p. 202; (3) U.S. Department of Energy, *Energy Projections to the Year 2010* (Washington, D.C.: Office of Policy, Planning and Analysis, 1983), pp. 3-7; (4) Hycarb Engineering Limited, *Canadian Heavy Crude Oil Market Analysis* (Calgary: Hycarb Engineering Ltd., 1984), p. 165; and (5) U.S. Energy Information Administration, *Annual Energy Review 1983* (Washington, D.C.: U.S. Government Printing Office, 1984), p. 79.

[a] Total supply approximated by the total of domestic production and imports. Demand figures include crude oil used for refined products only.

[b] Forecast values (1984 to 2000) are arithmetic averages of projections presented in sources (2), (3) and (4) above.

[c] Excess demand over supply figures from 1970 to 1982 may not correspond exactly to demand less supply due to various sources used.

TABLE D.2

U.S. FEDERAL HIGHWAY TRUST FUND GRANTS
1981-1982
(thousands of current U.S. dollars)

State or Territory	1981	1982
Alabama	224 507	184 477
Alaska	113 550	107 253
Arizona	137 633	115 311
Arkansas	102 754	85 232
California	547 537	491 610
Colorado	108 240	125 175
Connecticut	89 700	90 947
Delaware	39 967	32 416
District of Columbia	22 299	26 497
Florida	353 844	280 657
Georgia	237 889	208 124
Hawaii	50 718	48 091
Idaho	55 821	52 144
Illinois	384 762	338 608
Indiana	157 994	153 836
Iowa	130 461	110 843
Kansas	127 368	105 843
Kentucky	163 434	131 738
Louisiana	157 458	151 218
Maine	40 865	41 678
Maryland	266 702	322 845
Massachusetts	174 033	140 829
Michigan	226 722	237 600
Minnesota	182 550	191 090
Mississippi	73 018	84 049
Missouri	192 965	177 899
Montana	124 589	72 265
Nebraska	75 351	70 765
Nevada	97 192	43 050
New Hampshire	34 094	44 094
New Jersey	134 480	149 645
New Mexico	81 935	98 660
New York	431 713	382 104
North Carolina	199 697	162 226
North Dakota	64 946	41 947
Ohio	269 665	222 675
Oklahoma	92 754	55 158
Oregon	152 580	135 910
Pennsylvania	407 004	368 516
Rhode Island	32 669	24 457
South Carolina	81 296	83 241
South Dakota	61 772	51 955
Tennessee	209 961	159 582
Texas	564 395	421 208
Utah	133 415	100 044
Vermont	33 360	37 860
Virginia	254 535	164 284
Washington	306 142	295 894
West Virginia	213 291	180 993
Wisconsin	137 889	125 128
Wyoming	65 796	55 753
American Samoa	-	-
Guam	-	32
Northern Marianas	-	-
Puerto Rico	26 309	21 007
Trust Territory	-	-
Virgin Islands	-	1
Undistributed	31 311	21 047
TOTAL United States	8 680 963	7 625 517

SOURCE: U.S. Department of Commerce, Bureau of the Census, Federal Expenditures by State, Washington, D.C., 1982, 1983.

TABLE D.3

TOTAL PADD I ANNUAL ASPHALT USAGE
1970–1984
(tonnes)

	1970	1978	1979	1980	1981	1982	1983	1984 (projected)	1983 % Used for Paving
Connecticut	178 915	210 610	217 724	128 632	144 242	145 150	134 047	163 293	96.4
Delaware	91 035	38 898	41 730	71 483	77 110	81 646	37 820	68 038	96.1
Florida	774,629	924 409	959 801	916 564	922 607	925 328	1 040 638	1 360 777	68.4
Georgia	687 723	1 150 520	1 231 957	979 474	691 275	725 748	950 727	812 837	74.7
Maine	123 169	117 475	127 005	88 839	87 996	86 182	106 415	86 182	99.3
Maryland/D.C.	494 390	725 159	743 891	542 199	557 918	580 598	788 641	576 062	80.6
Massachusetts	499 262	340 945	381 017	251 449	255 826	281 227	205 637	272 155	66.7
New Hampshire	94 977	84 468	90 718	51 702	64 410	68 038	71 141	68 038	90.5
New Jersey	1 022 873	1 113 517	1 164 825	851 703	907 185	893 577	1 111 173	997 903	73.6
New York	984 354	1 122 538	1 247 379	1 006 329	997 903	997 903	1 042 180	1 133 981	83.5
North Carolina	635 826	657 776	671 316	630 402	397 347	408 233	584 766	500 766	83.4
Pennsylvania	1 149 574	1 171 501	1 194 762	1 045 204	997 903	997 903	724 419	1 020 583	78.2
Rhode Island	164 576	239 588	254 071	212 622	183 251	222 260	220 341	208 652	99.9
South Carolina	389 888	401 367	408 233	311 497	267 619	222 260	345 692	296 649	80.8
Vermont	47 561	3 270	9 071	8 687	9 071	13 607	11 477	18 143	100.0
Virginia	395 244	641 173	693 089	534 768	433 634	371 945	513 245	424 562	96.7
West Virginia	150 773	213 575	215 002	146 118	136 077	122 470	74 179	145 149	94.6
TOTAL[a]	7 824 717	9 156 496	9 651 541	7 777 678	7 131 381	7 144 081	7 962 546	8 153 778	79.7
TOTAL U.S.	26 954 601	31 728 465	31 612 676	29 087 504	22 951 781	23 096 930	24 769 263	27 960 349	77.9

SOURCE: The Asphalt Institute, Survey of 1983 Usage of Asphalt in the U.S. (College Park, Maryland: The Asphalt Institute, June 1984), p. 5.

[a] Figures may not add due to rounding.

TABLE D.4

TOTAL PADD II ANNUAL ASPHALT USAGE
1970–1984
(tonnes)

	1970	1978	1979	1980	1981	1982	1983	1984 (projected)	1983 % Used for Paving
Illinois	1 910 291	2 054 224	2 136 456	1 606 544	1 120 392	898 128	975 465	1 149 422	79.9
Indiana	1 049 676	1 555 544	1 546 776	1 053 028	1 067 774	997 920	1 051 894	752 976	69.7
Iowa	473 885	494 297	520 732	339 132	362 880	353 808	291 428	389 189	96.7
Kansas	383 497	620 323	612 360	616 698	343 829	349 272	263 617	439 085	82.7
Kentucky	527 755	547 410	533 434	412 796	355 622	535 248	382 029	628 690	88.4
Michigan	657 076	801 365	871 819	711 502	653 184	480 816	497 900	721 224	83.3
Minnesota	740 594	970 146	998 827	722 862	715 781	716 898	857 716	889 056	78.5
Missouri	907 550	1 069 200	968 890	816 325	584 237	607 824	621 652	754 790	80.7
Nebraska	189 056	252 211	287 582	146 731	123 379	136 080	121 471	199 584	98.5
North Dakota	208 798	191 560	206 342	141 586	136 987	140 616	198 133	172 368	99.0
Ohio	1 569 404	1 770 969	1 757 246	1 489 613	1 270 080	1 360 800	1 226 197	1 791 720	70.5
Oklahoma	782 603	801 738	541 598	985 741	616 896	635 040	787 566	889 056	85.1
South Dakota	134 902	136 740	149 688	130 116	97 070	117 936	97 007	127 008	98.5
Tennessee	632 634	1 029 172	868 190	689 824	502 588	771 120	545 332	902 664	76.7
Wisconsin	575 801	625 193	663 163	555 604	358 344	390 096	370 997	480 816	96.5
TOTAL[a]	10 743 532	11 520 089	11 879 603	10 418 102	8 309 045	8 491 392	8 288 404	10 287 648	79.9
U.S. TOTAL	26 954 601	31 728 465	31 612 676	29 087 504	22 951 781	23 096 930	24 769 263	27 960 349	77.9

SOURCE: The Asphalt Institute, Survey of 1983 Usage of Asphalt in the U.S. (College Park, Maryland: The Asphalt Institute, June 1984), p. 5.

[a] Figures may not add due to rounding.

TABLE D.5

UNITED STATES ASPHALT IMPORTS
1965-1983

	1965		1976		1980		1981		1982		1983		PADD I 1983	PADD II 1983
	(10^3 t)	(%)	(10^3 t)	(%)	(10^3 t)	(%)	(10^3 t)	(%)	(10^3 t)	(%)	(10^3 t)	(%)	(10^3 t)	(10^3 t)
Consumption	22 704.8	NA	24 895.0	NA	29 087.5	NA	22 951.8	NA	23 096.9	NA	24 769.3	NA	7 962.5	8 288.4
Production	NR	NA	NR	NA	27 746.0	NA	21 604.0	NA	21 717.0	NA	23 123.0	NA	NR	NR
Imports														
Canada	32.9	2.9	32.0	4.4	178.8	13.3	283.9	21.1	351.9	25.5	221.8	13.5	179.5	36.5
Mexico	-	-	0.1	-	24.0	1.8	37.7	2.8	49.8	3.6	139.3	8.5	0.1	-
Trinidad	7.0	0.6	0.3	-	0.1	-	0.2	-	0.2	-	0.2	-	0.2	-
N. Antilles	615.1	54.8	673.4	92.6	588.5	43.8	437.0	32.4	158.5	11.5	411.8	25.0	401.1	-
Venezuela	462.0	41.1	11.8	1.6	537.4	40.0	580.5	43.1	780.2	56.6	797.6	48.4	674.6	-
Sweden	-	-	-	-	-	-	-	-	14.4	1.0	18.3	1.1	18.3	-
U.K.	-	-	-	-	-	-	-	-	9.2	0.7	7.9	0.5	7 8	-
Netherlands	6.0	0.5	9.6	1.3	13.3	1.0	8.4	0.6	12.6	0.9	49.9	3.0	49.9	-
France	-	-	-	-	-	-	0.1	-	2.8	0.2	-	-	-	-
Total Imports	1 123.0	100.0	727.2	100.0	1 342.1	100.0	1 347.1	100.0	1 379.5	100.0	1 646.7	100.0	1 331.5	36.5

SOURCE: U.S. Department of Commerce, as referenced in The Asphalt Institute, *Survey of 1983 Usage of Asphalt in the U.S.* (College Park, Maryland: The Asphalt Institute, June 1984), pp. 5-6; and Asphalt Institute, *Asphalt Consumption data*.

TABLE D.6

CANADIAN EXPORTS OF ASPHALT BY PROVINCE[a]
1980-1983

	1980		1981		1982		1983	
	(tonnes)	(%)	(tonnes)	(%)	(tonnes)	(%)	(tonnes)	(%)
Atlantic Provinces	-	-	9 347	34.9	4 210	10.1	3 879	12.3
Quebec	12 632	100.0	15 899	59.4	18 136	43.6	16 031	50.9
Ontario	-	-	1 510	5.6	18 981	45.6	8 012	25.4
Manitoba	-	-	-	-	66	0.2	112	0.4
Saskatchewan	-	-	-	-	37	0.1	1 642	5.2
Alberta	-	-	-	-	-	-	1 827	5.8
British Columbia	-	-	-	-	146	0.4	-	-
TOTAL Canada	12 632	100.0	26 756	100.0	41 576	100.0	31 503	100.0

SOURCE: Canada, Statistics Canada, Refined Petroleum Products, Catalogue No. 45-004, monthly, 1980-1984 (Ottawa: Minister of Supply and Services, 1980-1984).

[a] This data not available for individual refineries or by destination.

TABLE D.7

PADD II CRUDE OIL PRODUCTION, IMPORTS, AND DEMAND
1970-1983
(10^6m^3)

Year	Production	Imports	Demand[a]	Imports/Demand (%)
1970	67.85	18.38	86.23	21.3
1971	63.73	21.79	85.52	25.5
1972	61.09	27.24	88.33	30.8
1973	56.21	41.40	97.61	42.4
1974	53.18	39.87	93.05	42.8
1975	51.24	44.94	96.18	46.7
1976	52.14	58.21	110.35	52.8
1977	51.74	82.16	133.90	61.4
1978	50.69	78.56	129.25	60.8
1979	50.56	88.53	139.09	63.6
1980	53.88	65.11	118.99	54.7
1981	56.54	39.49	96.03	41.1
1982	59.21	33.66	92.87	36.2
1983	64.84	30.75	95.59	32.2

SOURCE: American Petroleum Institute, Basic Petroleum Data Book: Petroleum Industry Statistics, Vol. IV, No. 3, September 1984 (Washington, D.C.: American Petroleum Institute, May 1984), Section IV, Table 4a-4b, and Section IX, Table 5.

[a] Demand estimated as production plus imports.

TABLE D.8

PADD II CRUDE OIL IMPORTS BY COUNTRY OF ORIGIN
1980-1984
($10^6 m^3$)

Country	1980	1981	1982	1983	1984[a]
Algeria	7 108.7	3 203.9	1 076.9	1 438.0	964.7
Angola	-	-	-	87.5	-
Brazil	-	56.8	-	-	-
Cameroon	776.7	1 165.1	1 743.1	641.5	64.6
Canada	7 568.3 (12)[b]	6 468.0 (17)[b]	9 023.7 (27)[b]	12 019.8 (39)[b]	7 131.9 (47)[b]
Congo	-	-	72.3	492.3	226.9
Ecuador	113.8	126.0	60.6	279.2	168.0
Egypt	83.5	148.8	390.0	144.3	-
Gabon	71.7	-	71.4	-	-
Ghana	7.9	-	-	-	-
Guatemala	82.6	43.1	114.3	181.3	-
Indonesia	-	90.9	-	23.6	-
Iran	300.4	-	237.1	1 020.0	165.3
Iraq	-	-	142.2	301.4	-
Libya	10 173.6	4 121.7	481.7	-	-
Mexico	8 849.0	6 003.8	5 962.3	6 614.6	3 761.3
Netherland Antilles	-	46.4	11.3	86.1	-
Netherlands	-	-	-	-	166.0
Neutral Zone	-	-	-	68.9	-
Nigeria	10 942.0	5 793.7	5 069.7	1 983.2	768.2
Norway	2 354.4	1 012.1	1 054.6	228.9	82.5
Oman	661.9	501.5	-	660.5	-
Peru	535.9	184.4	111.6	-	35.2
Qatar	257.5	80.8	306.4	-	-
Saudi Arabia	4 658.4	4 766.2	2 674.1	1 220.2	332.6
Trinidad & Tobago	1 882.9	789.3	172.1	942.4	812.0
Tunisia	143.2	-	-	71.0	-
UAE	2 258.9	860.2	781.4	-	170.9
U.K.	2 584.4	3 190.8	3 766.0	1 968.9	274.6
Venezuela	635.7	219.3	185.1	226.4	66.4
West Africa	162.6	202.6	-	-	-
TOTAL	62 213.9	39 075.5	33 507.8	30 690.8	15 191.1

SOURCE: American Petroleum Institute, Imported Crude Oil and Petroleum Products Reports (Database).

[a] 1984 figure is for January to June only.
[b] Bracketed figures are percentage of annual total.

TABLE D.9

PADD II HEAVY CRUDE OIL IMPORTS BY COUNTRY OF ORIGIN[a]
1979–1984
($10^6 m^3$)

Country	1979	1980	1981	1982	1983	1984[b]
Canada	6 022.4 (79)[c]	5 707.5 (71)[c]	5 762.9 (81)[c]	8 812.2 (79)[c]	11 138.2 (80)[c]	9 241.7 (79)[c]
Congo	–	–	–	72.3	492.3	311.2
Guatemala	–	64.2	43.1	114.3	113.5	–
Iran	171.8	–	–	–	–	–
Mexico	47.4	1 438.5	1 169.4	1 147.0	1 723.0	1 694.5
Neutral Zone	–	–	–	–	68.9	–
Nigeria	1 021.1	730.0	81.4	1 005.6	377.6	452.9
Saudi Arabia	63.5	41.7	36.9	–	–	67.3
Syria	72.6	–	–	–	–	–
Venezuela	178.0	–	–	–	–	–
TOTAL	7 576.8	7 982.0	7 093.8	11 151.4	13 913.5	11 767.6

SOURCE: American Petroleum Institute, *Imported Crude Oil and Petroleum Products Reports* (Database).

[a] Heavy crude oil defined as less than or equal to 29° API.
[b] 1984 figure is for first eleven months only.
[c] Bracketed figures are percentage of annual total.

APPENDIX E

DILUENT SUPPLY AND DEMAND DATA TABLES

TABLE E.1

CANADIAN PENTANES PLUS PRODUCTION AND RESERVES
1973-1982
(10^3m^3)

	Production[a]	Reserves[b]
1973	9 853.8	NR
1974	9 383.1	NR
1975	8 810.6	NR
1976	7 768.7	NR
1977	7 693.5	NR
1978	6 908.2	103 041
1979	6 866.3	93 492
1980	6 210.0	92 813
1981	5 818.2	90 541
1982	5 815.4	94 282
1983	5 408.1	93 640

SOURCE: Canadian Petroleum Association, CPA Statistical Handbook, updated to 1984 (Calgary: Canadian Petroleum Association, 1984), Section II Report, and Section III, Tables 3 and 4.

[a] Condensate and pentanes plus production.

[b] As at December 31. Includes established reserves recoverable under current technology and present and anticipated economic conditions, plus that judgement portion of contiguous recoverable reserves that are interpreted to exist with reasonable certainty.

TABLE E.2

COMPARISON OF FORECAST CANADIAN PENTANES PLUS SUPPLY
1981-2000
($10^3 m^3/d$)

Year	Chase Econometrics	EMR	ERCB	Foster Research[a]	Hycarb Engineering[b]	Total Average
1981	NR	15.8	NR	NR	15.7	15.7
1982	NR	15.4	NR	NR	15.4	15.4
1983	NR	14.5	14.9	NR	14.4	14.6
1984	12.4	15.0	14.4	14.7	13.1	13.9
1985	12.6	15.5	14.5	14.8	13.0	14.1
1986	12.7	16.0	14.6	15.0	14.0	14.5
1987	13.0	16.0	14.6	14.8	13.8	14.4
1988	13.7	17.0	14.7	14.6	15.0	15.0
1989	13.8	16.0	14.7	14.2	15.2	14.8
1990	14.0	16.0	15.0	13.9	15.0	14.8
1991	14.3	16.0	14.8	13.6	14.2	15.4
1992	14.3	15.0	14.8	13.1	14.1	14.3
1993	NR	15.0	14.4	12.6	14.2	14.1
1994	NR	15.0	14.8	12.1	14.4	14.1
1995	NR	15.0	14.5	11.7	14.6	14.0
1996	NR	NR	13.9	11.3	NR	12.6
1997	NR	NR	13.3	10.8	NR	12.1
1998	NR	NR	12.6	10.4	NR	11.5
1999	NR	NR	11.9	10.0	NR	11.0
2000	NR	13.0	11.2	9.6	12.1	11.5
Avg. Annual % Change 1985-2000[c]	1.8	(1.2)	(1.7)	(2.8)	(0.5)	(1.3)

SOURCES: (1) Leo de Bever, The Economic Impact of Changes in Energy Prices and Taxation Proposed by the Canadian Petroleum Association (Toronto: Chase Econometrics Canada, 1984), p. A.2; (2) Energy, Mines and Resources, Canada, Long-Term Energy Supply/Demand Outlook Spring 1984 Forecast (Ottawa: Energy, Mines and Resources, Canada, 1984), p. 35; (3) Alberta, Energy Resources Conservation Board, Alberta Oil Supply 1983-2007, Report 83-E (Calgary: Energy Resources Conservation Board, 1983), p. 32; (4) Foster Research, The Forecast Supply and Demand for Alberta Condensate for Blending with Heavy Crude Oil 1984-2000 (Calgary: Foster Research, 1984), pp. 30, 32, and 34; and (5) Hycarb Engineering Ltd., Canadian Heavy Crude Oil Market Analysis (Calgary: Hycarb Engineering Ltd., 1984), p. 121.

[a] Includes 300 cubic metres per day true condensate produced at the wellhead with crude oil.

[b] Pentanes plus from gas plant production only.

[c] Average percentage change for Chase Econometrics calculated from 1985 to 1992 as a figure for 2000 was not given.

TABLE E.3

COMPARISON OF FORECAST CANADIAN PENTANES PLUS DEMAND 1981-2000

Year	Foster Research[a]			Hycarb Engineering[b]			Total Average		
	Base Case ($10^3 m^3/d$)	Diluent Demand ($10^3 m^3/d$)	Diluent/ Base Case (%)	Base Case ($10^3 m^3/d$)	Diluent Demand ($10^3 m^3/d$)	Diluent/ Base Case (%)	Base Case ($10^3 m^3/d$)	Diluent Demand ($10^3 m^3/d$)	Diluent/ Base Case (%)
1981	NR	NR	NR	14.3	2.0	14.0	NA	NA	NA
1982	NR	NR	NR	15.4	3.3	21.4	NA	NA	NA
1983	NR	NR	NR	14.4	4.4	30.6	NA	NA	NA
1984	12.6	4.7	37.3	NR	NR	NA	NA	NR	NA
1985	14.0	5.4	38.6	13.0	5.9	45.4	13.5	5.7	42.2
1986	17.1	8.4	49.1	NR	NR	NA	NA	NA	NA
1987	17.7	9.1	51.4	NR	NR	NA	NA	NA	NA
1988	19.3	10.8	56.0	NR	NR	NA	NA	NA	NA
1989	19.5	11.3	57.9	NR	NR	NA	NA	NA	NA
1990	20.8	12.8	61.5	15.0	11.3	75.3	17.9	12.1	NA
1991	21.2	13.4	63.2	NR	NR	NA	NA	NA	67.6
1992	21.5	13.9	64.7	NR	NR	NA	NA	NA	NA
1993	21.8	14.5	66.5	NR	NR	NA	NA	NA	NA
1994	21.8	14.9	68.3	NR	NR	NA	NA	NA	NA
1995	21.8	15.3	70.2	19.3	18.2	94.3	20.6	16.8	NA
1996	20.7	15.2	73.4	NR	NR	NA	NA	NA	81.6
1997	20.4	15.3	75.0	NR	NR	NA	NA	NA	NA
1998	20.0	15.1	75.5	NR	NR	NA	NA	NA	NA
1999	19.7	15.0	76.1	NR	NR	NA	NA	NA	NA
2000	19.4	14.9	76.8	25.7	24.6	95.7	22.6	19.8	87.6
Avg. Annual % Change 1985-2000	2.2	7.0	NA	4.6	10.0	NA	3.5	8.7	NA

SOURCES: (1) Foster Research, The Forecast Supply and Demand for Alberta Condensate for Blending with Heavy Crude Oil 1984-2000 (Calgary: Foster Research, 1984), p. 30; and (2) Hycarb Engineering Ltd., Canadian Heavy Crude Oil Market Analysis (Calgary: Hycarb Engineering Ltd., 1984), p. 125.

[a] Base Case includes demand for miscible flooding, direct crude injections, Dome NGL system, and Bow River exports to Montana. Diluent includes demand for Alberta and Saskatchewan heavy crude oil, and Alberta bitumen.

[b] Base Case includes demand for NGL mixing, light/medium crude oil blending, and U.S. exports. Diluent includes demand for Alberta and Saskatchewan heavy crude oil, and Alberta bitumen.

TABLE E.4

COMPARISON OF FORECAST CANADIAN PENTANES PLUS AND DILUENT SUPPLY/DEMAND BALANCE

1981-2000

SURPLUS (SHORTFALL)[a]

($10^3 m^3/d$)

Year	Foster Research[b]		Hycarb Engineering		Total Average	
	Total Balance	Diluent Balance	Total Balance	Diluent Balance	Total Balance	Diluent Balance
1981	NR	NR	--	13.7	NA	NA
1982	NR	NR	--	12.1	NA	NA
1983	NR	NR	--	10.0	NA	NA
1984	2.1	10.0	NR	NR	NA	NA
1985	0.8	9.4	--	7.1	0.6	8.4
1986	(2.1)	6.6	NR	NR	NA	NA
1987	(2.9)	5.7	NR	NR	NA	NA
1988	(4.7)	3.8	NR	NR	NA	NA
1989	(5.3)	2.9	NR	NR	NA	NA
1990	(6.9)	1.1	--	3.7	(3.1)	2.7
1991	(7.5)	0.2	NR	NR	NA	NA
1992	(8.4)	(0.8)	NR	NR	NA	NA
1993	(9.2)	(1.9)	NR	NR	NA	NA
1994	(9.7)	(2.8)	NR	NR	NA	NA
1995	(10.1)	(3.6)	(4.7)	(3.6)	(6.6)	(2.8)
1996	(9.4)	(3.9)	NR	NR	NA	NA
1997	(9.6)	(4.5)	NR	NR	NA	NA
1998	(9.6)	(4.7)	NR	NR	NA	NA
1999	(9.7)	(5.0)	NR	NR	NA	NA
2000	(9.8)	(5.3)	(13.6)	(12.5)	(11.1)	(8.3)

SOURCES: Tables E.2 and E.3.

[a] Supply less demand.

[b] Base Case only.

TABLE E.5

DILUENT REQUIREMENTS FOR FORECAST CANADIAN HEAVY CRUDE OIL PRODUCTION
1984-2000
($10^3m^3/d$)

Year	Total Supply of Canadian Heavy Crude Oil			Diluent Required for Total Supply[a]			Exportable Surplus of Canadian Heavy Crude Oil[b]			Diluent Required for Exportable Surplus[a]		
	Conventional Heavy	Bitumen	Total	Conventional Heavy	Bitumen	Total	Conventional Heavy[c]	Bitumen[c]	Total	Conventional Heavy	Bitumen	Total
1984	33.6	5.2	33.8	10.1	2.6	12.7	20.8	3.2	24.0	6.2	1.6	7.8
1985	32.9	8.0	40.9	9.9	4.0	13.9	19.8	4.8	24.6	5.9	2.4	8.3
1986	33.7	13.0	46.7	10.1	7.5	17.6	16.3	6.3	22.6	4.9	3.2	8.1
1987	33.0	16.0	49.0	9.9	8.0	17.9	13.7	6.6	20.3	4.1	3.3	7.4
1990	33.2	16.0	49.2	10.0	8.0	18.1	9.1	4.4	13.5	2.7	2.2	4.9
1995	33.7	16.0	49.7	10.1	8.0	18.1	6.8	3.3	10.1	2.0	1.7	3.7
2000	30.6	16.0	46.6	9.2	8.0	17.2	3.4	1.7	5.1	1.0	0.8	1.8

SOURCE: Table 4.2

[a] Diluent required based on 30 percent of conventional volumes and 50 percent of bitumen volumes.

[b] Base Case.

[c] Conventional Heavy/Bitumen breakdown for the exportable surplus based on the relative proportions of these two factors in Total Supply.

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